Hawaiian Electric

DRAFT

REQUEST FOR PROPOSALS

FOR

RENEWABLE DISPATCHABLE GENERATION

AND

ENERGY STORAGE

ISLAND OF O‘AHU

DECEMBER 22, 2022

Docket No. 2017-0352

Table of Contents

List of Appendices

Chapter 1: Introduction and General Information

Hawaiian Electric Company, Inc. ("Hawaiian Electric" or the "Company") seeks proposals to acquire at least 965 gigawatt hours ("GWh") annually of variable renewable dispatchable generation, and proposals to acquire 500 to 700 megawatts ("MW") of renewable firm capacity through this Request for Proposals ("RFP"), as defined further in Section 1.2.2.[1] Hawaiian Electric will target having (1) the 965 GWh of variable renewable dispatchable generation acquired through this RFP in service by December 1, 2027, (2) 300 to 500 MW of renewable firm capacity acquired through this RFP in service by the end of 2029, and (3) an additional 200 MW of renewable firm capacity acquired through this RFP in service by the end of 2033. From the targeted amount of renewable firm capacity for 2029, Hawaiian Electric will seek proposals for at least 150 MW of non-spinning reserves that can be dispatched from offline to full load within 15 minutes or less. Proposers should submit Proposals to achieve commercial operations as soon as possible to address urgent reliability needs, especially for the renewable firm capacity. Proposers are expected to have their permitting requirements addressed and provide a realistic project schedule in their Proposals. The Company stresses that Proposers must fully demonstrate that their Projects are able to meet their Guaranteed Commercial Operations Date. Failure to do so may result in Proposals not advancing through the evaluation phase of the RFP. This RFP is intended to replace and incorporate the scope of the draft Oahu Renewable Dispatchable Firm Generation RFP, filed on February 28, 2022.

The Company seeks three general types of projects in this RFP, 1) new variable renewable dispatchable generation projects (with or without energy storage systems),[2] 2) standalone energy storage projects, and 3) new firm renewable dispatchable generation projects. The Company will also accept Proposals from existing renewable generation projects or existing fossil fuel projects that convert to a renewable source for new terms after the expiration of their current agreements. Any existing project's Proposal must meet all of the terms of this RFP, including agreement to use the applicable model Stage 3 Contract attached hereto. Existing projects, however, still maintain the rights to use their existing interconnection facilities and points of interconnection.[3] Through this RFP, the Company intends to contract any variable renewable dispatchable generation projects using its Model Renewable Dispatchable Generation Power Purchase Agreement ("RDG PPA"),[4] which treats variable generation facilities as fully dispatchable; any firm[5] dispatchable generation projects using its Model Firm Renewable Dispatchable Generation

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[1] Procurement fulfillment will be dependent on the types of Proposals received in this RFP. The Company may consider selecting Proposals that will provide additional energy and other services in excess of or less than the targeted amounts depending on whether such Proposals demonstrate benefits to customers and meet the needs of the grid.
[2] Any photovoltaic ("PV") projects must be paired with an energy storage component.
[3] Sections 1.2.10, 2.2.1, and Appendix H interconnection cost applications may not apply to existing projects currently interconnected and operating on the Hawaiian Electric System. Please contact the Company via the RFP Email Address in Section 1.6 to seek clarification on what is required for existing projects.
[4] The Company offers a Model PV+BESS RDG PPA version for PV paired with energy storage and a Model Wind+BESS RDG PPA version for wind paired with energy storage. If a generation-only wind proposal is proposed, the BESS-specific provisions will be removed from the Model Wind+BESS RDG PPA.
[5] Firm generation is available up to 100% of the contract capacity at any time under Company dispatch, except during periods of outage and deration, independent of source energy resource availability.

Power Purchase Agreement ("Firm PPA"); and any standalone energy storage projects using its Model Energy Storage Purchase Agreement ("ESPA"). Collectively, these model purchase agreements are referred to as the "Stage 3 Contracts".[6] If a proposed Project utilizes a technology that is not encompassed by the model purchase agreements provided, then the terms of the applicable model purchase agreement will be modified to address the specific technology and/or component.[7]

Each successful Proposer will provide variable renewable dispatchable generation with/without energy storage, standalone energy storage, or firm renewable dispatchable generation to the Company pursuant to the terms of an applicable Stage 3 Contract which will be negotiated between the Company and Proposer, and also be subject to review and approval by the State of Hawaiʻi Public Utilities Commission. Proposers are instructed to thoroughly review their respective model Stage 3 Contract attached as Appendix J, K, L, and M that represents the technology of their project. The structure of the RDG PPA, Firm PPA and ESPA intends to provide monthly payments to the Proposer by the Company (e.g., Lump Sum Payment, Capacity Charge payment), based upon the energy potential or contract capacity, as applicable, of the Facility, regardless of the actual energy dispatched.[8] In exchange, the utility maintains full dispatch control of the Facility as needed. Under the RDG PPA, Firm PPA and ESPA, each Facility must meet certain requirements to receive the full Lump Sum Payment/Capacity Charge payment (as applicable) each month. The Firm PPA also provides for a separate monthly Energy Charge payment. These requirements ensure that each plant is available to the Company for dispatch to meet System needs. The Company intends to use all Projects selected for the Final Award Group in accordance with the performance and dispatchability requirements described in the model Stage 3 Contracts to meet various grid needs identified in Appendix I of this RFP ("GNA Update").

Appendix I provides information to Proposers on the grid needs of the System based on computer modeling of the future dispatch of the System, including how new resources acquired through this RFP may be dispatched to provide various services (e.g., 20- and 1-minute upward and downward regulating reserve, ramp, and capacity). In addition to the expected provision for grid services, the GNA Update also provides the portfolio of projects' aggregated dispatch on typical days to inform Proposers when and how the projects may be utilized in addition to existing system resources. In turn, Proposers can use this information to design their Project to better fit within the Oʻahu resource portfolio. Proposers must review Appendix I. The GNA Update in Appendix I was determined by modeling which selected the addition of resources including onshore wind, standalone storage, and geothermal resources. The Company, however, is committed to selecting a portfolio of projects based on the results of the RFP to meet the System needs and is not focused on any particular technology. Therefore, acquiring the amount of grid needs set forth in Appendix I will be dependent on the final resource mix selected. As

[6] Herein, the term "Stage 3 Contract" will be used generically to refer to the applicable purchase agreement for that technology (i.e., PV+BESS RDG PPA, Wind+BESS RDG PPA, Firm PPA, or ESPA).
[7] Contact the Company if there is any uncertainty with which model Stage 3 Contract the Proposer's technology aligns.
[8] Firm proposals may include an Energy Charge payment component in addition to the Capacity Charge payment component. The Energy Charge payment would be based on actual production and delivery to the grid. The Firm PPA allows the Company dispatch rights and does not guarantee Seller any amount of energy will be delivered to the Point of Interconnection - in the event that the Company does not accept any energy at the Point of Interconnection, the Company will not pay any Energy Charge payment.

detailed in this RFP, during the detailed evaluation, modeling will be performed to assess the grid resources being provided by the final selected portfolios.

To assist Proposers in developing costs of potential projects, the Company also offers interconnection facilities cost and schedule information in Appendix H. The information provided in Appendix H can be used to approximate the cost for Company-Owned Interconnection Facilities, including substation, telecommunications, security, transmission and distribution lines, and project management.

The Company or its Affiliates may submit a Proposal in response to this RFP subject to the requirements of this RFP.

The Company will evaluate Proposals using the evaluation and selection process described in Chapter 4. The Company will evaluate and select Proposals based on both price and non-price factors that impact the Company, its customers, and communities affected by the proposed Projects. The number of Projects that the Company may acquire from this RFP depends on, among other things, the quality and cost-effectiveness of bids received in response to this RFP; economic comparison to other RFP responses; updates to the Company's forecasts; transmission and distribution availability; and changes to regulatory or legal requirements. If attractive Proposals are received that will provide energy and other services in excess of the targeted amounts, the Company will consider selecting such Proposal(s) if benefits to customers are demonstrated.

All requirements necessary to submit a Proposal(s) are stated in this RFP. A description of the technical requirements for Proposers is included in the body of this RFP, Appendix B, and in the applicable RDG PPA, Firm PPA, and ESPA attached as Appendix J, K, L, and M.

All capitalized terms used in this RFP shall have the meaning set forth in the glossary of defined terms attached as Appendix A. Capitalized terms that are not included in Appendix A shall have the meaning ascribed in this RFP.

1.1 Authority and Purpose of the Request for Proposals

1.1.1 This RFP is issued in response to Order No. 38735 issued on December 1, 2022 in Docket No. 2017-0352 as part of the procurement process established by the PUC.

1.1.2 While storage was not contemplated in Decision and Order ("D&O") No. 23121 in Docket No. 03-0372 (To Investigate Competitive Bidding for New Generating Capacity in Hawai'i), which sets forth the PUC's Framework for Competitive Bidding ("Framework" or "Competitive Bidding Framework"), the Company intends to follow the Framework to the extent applicable for this RFP. This RFP is also consistent with the Updated Framework for Competitive Bidding ("Updated Framework"), which was drafted to be more inclusive of various technologies, and filed on February 12, 2021 in Docket No. 2018-0165. Order No. 38481 issued on June 30, 2022 in that docket recently approved the Updated Framework for use in the first round of integrated grid planning. Until the first round of integrated grid planning RFPs commence, the Company will continue to follow the Framework.

1.1.3 Proposers must review Appendix I, the Company's GNA Update, to inform Proposers of the assessment performed and the resulting recommended grid needs identified that shape the basis of this RFP, including the manner in which the modeling software chose to dispatch the energy based on System need. As conveyed in the Introduction above, the GNA Update provides the portfolio of projects' aggregated dispatch on typical days to inform Proposers when and how projects may be utilized, so Proposers can use this information to design their Project to better fit within the O'ahu resource portfolio.

1.2 Scope of the RFP

1.2.1 The Company has established two separate targets in this RFP. The first is for variable renewable dispatchable generation projects (with or without energy storage systems) and standalone energy storage projects. The second is for firm renewable dispatchable generation projects. There is no predetermined preference for a particular renewable energy generation or storage technology; however, the firm renewable dispatchable generation targets must be from a synchronous machine-based generation technology. The two separate targets are also intended to diversify the generation portfolio on the island of O'ahu and reduce procurement and execution risks associated with a potentially homogenous Final Award Group, if not for separate procurement targets.

1.2.2 Proposals may be submitted as:

- Target 1: Renewable Dispatchable Generation Need
  - Variable renewable generation Projects ("Variable Generation Projects")[9]
  - Paired variable renewable generation with energy storage Projects ("Paired Projects")
  - Standalone energy storage Projects ("Standalone Storage Projects")
- Target 2: Firm Renewable Generation Need
  - Firm renewable generation Projects[10]

1.2.3 All Proposals with a generation component submitted in response to this RFP must utilize qualified renewable energy resource(s), as defined under the Hawai'i Renewable Portfolio Standards ("RPS") law.[11] By statute, "Renewable Energy" means energy generated or produced using the following sources: (1) wind; (2) the sun; (3) falling water; (4) biogas, including landfill and sewage-based digester gas; (5) geothermal; (6) ocean water, currents, and waves, including ocean thermal energy conversion; (7) biomass, including biomass crops, agricultural and animal residues and wastes, and municipal solid waste and other solid waste; (8) biofuels; and (9) hydrogen produced from renewable energy sources.[12]

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[9] Variable Generation Projects, with the exception of PV, do not need to include an energy storage component. PV generation projects must be paired with an energy storage component and proposed as a Paired Project.

[10] As noted in footnote [6] above, firm generation is a synchronous machine based technology that is available up to 100% of the contract capacity at any time under Company dispatch for as long as needed, except during periods of outage and deration, independent of source energy resource availability. Firm generation must not be energy limited or weather dependent.

[11] RPS requirements in Hawai'i are codified in Hawai'i Revised Statutes ("HRS") §§ 269-91 through 269-95.

[12] See HRS § 269-91.

All Proposals with a generation component that operates on fuel must include any and all costs of such fuel for the entire proposed Firm PPA term in its Proposal with the exception of biofuel proposals. Proposals operating on biofuel[13] do not need to include the cost of biofuel in their Proposal cost, but those Proposals must provide a biofuel price forecast. The Proposal will not have to guarantee the biofuel forecast pricing, but the Company reserves the right to use an alternative appropriate fuel forecast when evaluating the Proposal (i.e., the Company may choose to use the Company's biofuel forecast, or potentially look at more than one fuel forecast for evaluation purposes).

Proposers must also describe their fuel supply plan that will ensure sufficient fuel and other necessary consumables required for unconstrained dispatch and fuel storage on site for at least fourteen (14) days of 16 hours of Full Load[14] operation per day. If offsite storage connected via pipeline is utilized, or is otherwise immediately accessible, the on-site requirement can be reduced to seven (7) days of 16 hours of Full Load operation with the additional 7 days off site. In no event will there be less than seven days of fuel (based on 16 hours of operation) available on site.[15] This shall be calculated using the following Fuel Floor Requirement Calculation:

Average Fuel Usage Per Day (Based on 16 hours Full Load) x Minimum Floor Requirement (7 or14 days - Minimum Number of days required on Hand. See below to determine the Minimum Floor Requirement Amount.)

- ***Example for Illustration Purposes (numbers below are for illustration purposes only):***
  - *Average Fuel Usage Per Day (Based on 16 Hours Full Load) = 2,000 barrels*
  - *Minimum Floor Requirement = 14 days (2 weeks) for fuel being stored on-site; 7 days (1 week) for fuel being stored offsite but connected via a pipeline.*
  - *2,000 barrels x 14 days = 28,000 barrels*

28,000 barrels is the minimum Floor Requirement based on average fuel usage of 16 hours full load.

In addition, Proposers must provide the following:

- Storage of 30 days of fuel and necessary consumables on island based on normal expected operation.[16] Fuel may be owned or under guaranteed contract and stored

[13] Biofuel is defined in HRS § 269-91: "Biofuels" means liquid or gaseous fuels produced from organic sources such as biomass crops, agricultural residues and oil crops, such as palm oil, canola oil, soybean oil, waste cooking oil, grease, and food wastes, animal residues and wastes, and sewage and landfill wastes.

[14] Full Load is defined as the Contract Firm Capacity as defined in the Model Firm PPA.

[15] Days refer to calendar days, unless the term "business day" is used, which means calendar day excluding weekends and federal and State of Hawai‘i holidays.

[16] The Grid Needs Assessment information provided in App. I of the RFPs can be used to estimate the future normal expected operation for initial fuel supply planning purposes. Over the term of the Project, the future normal expected operation shall be based upon (i) the average level of Company Dispatch during the previous six (6) months and (ii) the expected level of Company Dispatch during the following month as indicated by Company.

onsite or offsite but in all cases must be on island. Reserve fuel may be any fuel the developer is permitted to consume.

- A fuel management plan that guarantees that fuel and necessary consumables stored offsite will be delivered to the Project site, particularly during an emergency event when fuel is required.

Alternative fuel management plans that demonstrate the resilience sought by the above requirements may be considered. The fuel requirements may be revisited and adjusted downward in the future if needs so require.

All Proposals with a generation component that operate on fuel must also commit to provide fuel for the entire proposed term of the Firm PPA and, with the exception of biofuel, provide evidence, such as in the form of contracts, that the fuel will be secured for the duration of the Firm PPA term.[17] All Proposals utilizing a fuel source must also specify any minimum monthly, quarterly, and/or annual fuel purchases in their fuel contract. Proposers for facilities that elect to use a liquid or gaseous fuel source must also be capable of operating using fossil fuel, including obtaining the proper permitting, and include the costs for the use of such fuel in its Proposal. The Company will maintain the right to consent to any fuel supply changes during the term of the PPA. It is the responsibility of the Seller to operate within the limits of any applicable permits while being able to operate per the terms in the Firm PPA. Any operational constraints need to be identified in the Proposal. In the event that there are changes to operational limitations, such changes will be memorialized through an amendment to the Firm PPA. At a minimum Proposers are responsible for researching permitting and environmental requirements in existence and identifying such requirements and any resulting operational limits in their Proposal.

To assist with proposal preparation, the Near-Term Grid Needs Assessment for O‘ahu, attached as Appendix I, provides the annual capacity factors, as shown below, for the new firm thermal units that were modeled as a proxy for the renewable firm capacity targets included in this RFP.

O‘ahu – Base Case (see Appendix I, page 123)

Capacity Factor (%)	Base_508_Staggered		Base_607_Staggered			Base_688_Staggered		
	CT	CC	CT	ICE	CC	CT	Biomass	CC
2029	12%	N/A	4%	26%	N/A	1%	97%	N/A
2030	5%	N/A	2%	10%	N/A	0%	76%	N/A
2031	5%	N/A	2%	8%	N/A	0%	73%	N/A
2032	4%	N/A	1%	8%	N/A	0%	72%	N/A
2033	0%	10%	0%	2%	11%	0%	69%	1%
2034	1%	8%	0%	2%	9%	0%	66%	1%
2035	0%	6%	0%	1%	6%	0%	59%	0%

[17] Proposals operating on biofuel must commit to providing fuel for the entire duration, but do not have to provide evidence of a fuel supply contract for the entire duration of the contract. However, Proposals utilizing biofuel must commit to provide evidence of a fuel supply for at least the first 3 years of the Firm PPA term.

O'ahu – Land Constrained Case (see Appendix I, page 125)

Capacity Factor (%)	LC_508_Staggered		LC_607_Staggered			LC_688_Staggered		
	CT	CC	CT	ICE	CC	CT	Biomass	CC
2029	24%	N/A	10%	44%	N/A	4%	97%	N/A
2030	13%	N/A	6%	21%	N/A	3%	95%	N/A
2031	13%	N/A	6%	23%	N/A	2%	96%	N/A
2032	23%	N/A	12%	36%	N/A	5%	96%	N/A
2033	11%	56%	4%	23%	50%	1%	96%	24%
2034	12%	57%	5%	27%	50%	2%	96%	24%
2035	3%	31%	1%	9%	28%	0%	89%	11%

The capacity factors provided above are intended to represent typical conditions, and are for illustrative purposes only. If an emergency occurs like a severe weather event that causes the forced outage of multiple resources, higher capacity factors of the new firm thermal units may be required. Additionally, many other factors may affect the capacity factor or run hours of generating units, such as the type and cost of fuel oil used, heat rate, existing generating units that remain in-service or retired, the amount of variable renewable dispatchable projects on the system, among others.

1.2.4 Each Proposal submitted into this RFP must represent a Project that is capable of meeting the requirements of this RFP without having to rely on the completion or implementation of any other Project, or without having to rely on a proposed change in law, rule, or regulation.

1.2.5 Proposals that will require System upgrades and the construction of which, in the reasonable judgment of the Company (in consultation with the Independent Observer), creates a significant risk that their Project's Guaranteed Commercial Operations Date ("GCOD") will not be met, will not be considered in this RFP.

1.2.6 Projects submitted into this RFP must be located on the island of O'ahu.

1.2.7 The term of the Firm PPA for any proposed firm renewable dispatchable generation Project must be thirty (30) years. Proposals utilizing the RDG PPA or ESPA, for variable renewable dispatchable generation projects (with or without energy storage systems) and standalone energy storage projects, respectively, may propose the term of such contract.

1.2.8 Proposers must determine their Project Site, interconnection facilities and route of interconnection facilities, and Point(s) of Interconnection ("POI").

1.2.9 Proposers must locate all Project infrastructure within areas of their Site that are:

- outside the 3.2 feet sea level rise exposure area (SLR-XA) as described in the Hawai‘i Sea Level Rise Vulnerability, and Adaptation Report (2017);[18]
- not located within a Tsunami Evacuation Zone;[19] and
- not located within the Hawaii Department of Land and Natural Resources flood map's flood zones A, AE, AEF, AH, AO, VE based on the Federal Emergency Management Agency's Digital Flood Insurance Rate Maps.[20]

All equipment required for a Proposer's project must be sited within the proposed Project Site with no assumptions that any equipment will be sited on Company property unless specified by the Company.

1.2.10 Projects must either interconnect to the Hawaiian Electric System (1) at the 138 kV transmission-level via the transmission lines identified in Section 2.2.1 and constructing a new substation to the 138 kV transmission-level line, (2) via 138 kV substations – Ewa Nui, Campbell Estate Industrial Park, Hoohana, Kahe, AES, Koolau, or Waiau, or (3) via 46 kV subtransmission-level as described in Section 2.2.1. Proposers must inquire about the transmission line available MW capacity or substation conditions. See Section 2.2.1 below. To the extent the Company's existing land rights for any Company-provided interconnection location are not perpetual, Proposers will remain responsible for securing land rights in Company's favor for any such Company-provided interconnection location in accordance with the requirements of the applicable Stage 3 Contract.

1.2.11 A Project's size must be greater than 5 MW, the threshold for a waiver from the Competitive Bidding Framework applicable to O‘ahu. No single point of failure from the Facility shall result in a decrease in active power output measured at the Project's POI greater than 142 MW. Additionally, in meeting the single point of failure requirement, if the Project's generator step-up transformers are operated in parallel, the parallel step-up transformers must be equal in size (MVA) and have the same electrical characteristics and available tap positions. Each generator step-up transformer must have its own POI not in adjacent positions of the same breaker-and-a-half bay into the Hawaiian Electric System that can be independently dispatched via the Company's Energy Management System. Revisions will need to be made to the Stage 3 Contract to account for multiple POI.

1.2.12 Contracts for Projects selected through this RFP must use the appropriate Stage 3 Contract as described in Section 3.8. Under the RDG PPA and Firm PPA, the Company shall maintain exclusive rights to fully direct dispatch of the Facility, subject to

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[18] Hawai‘i Climate Change Mitigation and Adaptation Commission. 2017. Hawai‘i Sea Level Rise Vulnerability and Adaptation Report. Prepared by Tetra Tech, Inc. and the State of Hawai‘i Department of Land and Natural Resources, Office of Conservation and Coastal Lands, under the State of Hawai‘i Department of Land and Natural Resources Contract No: 64064. This report is available at: https://climateadaptation.hawaii.gov/wp-content/uploads/2017/12/SLR-Report_Dec2017.pdf

[19] See Hawai‘i Sea Level Rise Viewer at https://www.pacioos.hawaii.edu/shoreline/slr-hawaii/, and National Oceanic and Atmospheric Administration (NOAA) interactive map in partnership with the State of Hawai‘i at https://tsunami.coast.noaa.gov/#/. Projects infrastructure must be outside the "Tsunami Evacuation Zone" (but not necessary to be outside the "Extreme Tsunami Evacuation Zone").

[20] See Hawaii Department of Land and Natural Resources Flood Hazard Assessment Tool at http://gis.hawaiinfip.org/FHAT/.

availability of the resource for those Projects using the RDG PPA. Under the ESPA, the Company shall maintain exclusive rights to fully direct the charging and discharging of the Facility. Additionally, due to the critical nature and usage of this to support the grid, the ability to control and tune the Facility's response to certain grid events and conditions is an important aspect that will be required of all facilities.

1.2.13 The storage component of a Paired Project will be charged from its generation component during periods when full potential export of the generation component is not being dispatched by the Company. Energy in the storage component will be exported to the Company's System subject to Company dispatch. The storage component of a Paired Project must be sized to support the Facility's Net Nameplate Capacity (in MW)[21] for at least two (2) continuous hours for a Wind+BESS Project or at least four (4) continuous hours for a PV+BESS Project throughout the term of the respective RDG PPA and support a minimum of 365 full charging/discharging cycles per year (or 366 full charging/discharging cycles per leap year).

For example, for a paired 10 MW PV facility, the energy storage component must be able to store and discharge at least 40 MWh of energy in a cycle throughout the term of the PV+BESS RDG PPA. For a paired 10 MW wind facility, the Proposer must propose an energy storage component that is able to store and discharge at least 20 MWh of energy in a cycle throughout the term of the Wind+BESS RDG PPA.

Paired Projects must also be capable of being 100% charged from the grid at the direction of the Company from the GCOD.

1.2.14 The amount of energy discharged from any energy storage component (Paired Project or Standalone Storage Project) in a year will be limited to the BESS Contract Capacity (in MWh) multiplied by the number of days in that year. An energy storage component may be dispatched more than once per day, subject to such discharge energy limitations.

1.2.15 Standalone Storage Projects will be charged from the grid and provide energy to the Company during times that are deemed by the Company to be beneficial to the System. These facilities must be connected to the grid at all times, with the exception of allowed maintenance periods.

1.2.15.1 Standalone Storage Projects must be sized to support the Facility's Net Nameplate Capacity (in MW) for either two (2) or four (4) continuous hours throughout the term of the ESPA and support a minimum of 365 full charging/discharging cycles per year (or 366 full charging/discharging cycles per leap year).

For example, for a 10 MW facility, the energy storage component must be able to store and discharge at least 20 MWh or 40 MWh of energy in a cycle throughout the term of the ESPA.

[21] A Project's Net Nameplate Capacity is the net maximum instantaneous active power capability of the Facility at the point of interconnection, considering: nameplate power rating of energy generating equipment sizing, expected losses in delivery of power to the POI, and any project control system involved in managing the delivery of power to the POI.

For both Paired Projects and Standalone Storage Projects, the inverter which interfaces between the BESS DC side and AC side must be a grid-forming control type inverter.

1.2.16 Proposals for Variable Generation Projects, Paired Projects and Standalone Storage Projects must specify a GCOD no later than December 1, 2027. A Proposer's GCOD set forth in its Proposal will be the GCOD in any resulting Stage 3 Contract if such Proposal is selected to the Final Award Group. Proposers will not be able to request a change in the GCOD set forth in their Proposals.

1.2.17 Proposals for Firm renewable dispatchable generation Projects must specify a GCOD as set forth in the table below. Proposals with multiple variations must include a variation that indicates the earliest possible GCOD the Proposal can achieve. A Proposer's GCOD set forth in its accepted Proposal or variation will be the GCOD in any resulting Firm PPA if such Proposal is selected to the Final Award Group. Proposers will not be able to request a change in the GCOD set forth in their accepted Proposal or variation.

Firm Renewable Generation	**GCOD No later than December 1, 2029**	**GCOD No later than December 1, 2033**
MW requested	300 to 500 MW	200 MW

1.2.18 If selected, Proposers will be responsible for all costs throughout the term of the Stage 3 Contract, including but not limited to Project development, completion of an Interconnection Requirements Study ("IRS"), the cost of conducting a greenhouse gas ("GHG") emissions analysis, land acquisition, permitting, financing, construction of the Facility and all Interconnection Facilities including system upgrades, all fuel to operate the Facility, and the operation and maintenance ("O&M") of the Facility.

1.2.19 If selected, Proposers will be solely responsible for the decommissioning of the Project and the restoration of the Site upon the expiration of the Stage 3 Contract, as described in Attachment G, Section 7 of the RDG PPA, Firm PPA or ESPA.

1.2.20 If selected, Proposers shall pursue all available applicable federal and state tax credits (including, without limitation, all available applicable tax credits from the federal Inflation Reduction Act). Proposal pricing must be set to incorporate the benefit of such available federal tax credits. In the event additional federal tax credits become available through new tax legislation after Proposals are submitted but before Proposals are selected to the Final Award Group, the Company may require applicable Proposals propose an additional downward only price adjustment to allow the benefits of those additional tax credits to be passed along to the Company's customers.

However, to mitigate the risk on Proposers due solely to potential changes to Hawai'i state's tax credit law before a selected Project reaches commercial operations, Proposal pricing shall be set without including any state tax credits. If a Proposal is selected, the Stage 3 Contract for the Project will require the Proposer to pursue the maximum available state tax credit and remit tax credit proceeds to the Company for customers' benefit as described in Attachment J of the RDG PPA, Firm PPA, or ESPA. The Stage 3 Contract will also provide that the Proposer will be responsible for payment of liquidated damages for failure to pursue such maximum available state tax credit.

1.2.21 If selected, Proposers will submit project schedules as required per Attachment S of the Stage 3 Contract, including creating their schedules using Microsoft Project and submitted in .mpp file format.

1.3 Competitive Bidding Framework

Consistent with the Framework, this RFP outlines the Company's requirements in relation to the resources being solicited and the procedures for conducting the RFP process. It also includes information and instructions to prospective Proposers participating in and responding to this RFP.

1.4 Role of the Independent Observer and Independent Engineer

1.4.1 Part III.C.1 of the Framework sets forth the circumstances under which an Independent Observer is required in a competitive bidding process. The Independent Observer will advise and monitor all phases of the RFP process and will coordinate with PUC staff throughout the RFP process to ensure that the RFP is undertaken in a fair and unbiased manner. In particular, the Company will review and discuss with the Independent Observer decisions regarding the evaluation, disqualification, non-selection, and selection of Proposals.

1.4.2 The role of the Independent Observer, as described in the Framework, will include, but is not limited to:

- Monitor all steps in the competitive bidding process
- Monitor communications (and communications protocols) with Proposers
- Monitor adherence to the Company's Code of Conduct
- Submit comments and recommendations, if any, to the PUC concerning the RFP
- Review the Company's Proposal evaluation methodology, models, criteria, and assumptions
- Review the Company's evaluation of Proposals
- Advise the Company on its decision-making
- Participate in dispute resolution as set forth in Section 1.10
- Monitor contract negotiations with Proposers
- Report to the PUC on monitoring results during each stage of the competitive bidding process
- Provide an overall assessment of whether the goals of the RFP were achieved

An Independent Engineer will be engaged by the PUC for this RFP. The Independent Engineer will provide technical expertise to oversee matters related to interconnection in the RFP process. The Independent Engineer's role will include, but not be limited to:

- Reviewing the Company's requirements and standards for interconnection
- Review the interconnection documents provided by Proposers

- Participate in discussions with the Company and Proposers over interconnection requirements, scope, and cost
- Verify any one-time Net Energy Potential RFP Projection adjustment allowed in Section 3.10.1.1
- Review requirements imposed on Proposers which bear cost implications
- Review system available MW capacity information to Proposers to ensure accuracy
- Oversee technical issue dispute resolution
- Investigate and review the cost of interconnection from the Proposers

1.4.3 The Independent Observer for this RFP is: **Bates White, LLC**.
The Independent Observer Email Address: vincent.musco@bateswhite.com

The Independent Engineer for this RFP is: **PA Consulting**
The Independent Engineer Email Address: suman.gautam@paconsulting.com

1.5 Communications Between the Company and Proposers – Code of Conduct Procedures Manual

1.5.1 Communications and other procedures under this RFP are governed by the "Code of Conduct Procedures Manual" (also referred to as the "Procedures Manual") developed by the Company as required by the Framework, and attached as Appendix C.

1.5.2 All Proposal communication with prospective Proposers will be conducted via the Company's RFP website, Electronic Procurement Platform, and/or electronic mail ("Email") through the address specified in Section 1.6 (the "RFP Email Address"). Phone communication or face-to-face meetings will not be supported.

To ensure the Independent Observer can monitor communication, questions regarding the RFP or a proposed Project submitted to the RFP Email Address should include the Independent Observer Email Address found in Section 1.4.3 above. In addition to the Independent Observer who should be included on all correspondence to the Company, Proposers should also include the Independent Engineer on any questions to the RFP Email Address of a technical nature. Frequently asked questions submitted by prospective Proposers and the answers to those questions may be posted on the Company's RFP website. The Company reserves the right to respond only to comments and questions it deems are appropriate and relevant to the RFP. Proposers shall submit questions no later than fifteen days before the respective Proposal Due Date (RFP Schedule in Section 3.1, Table 2). The Company will endeavor to respond to all questions no later than five days before the respective Proposal Due Date.

1.5.3 After Proposals have been submitted, the Company may contact individual Proposers for purposes of clarifying their Proposal(s).

1.5.4 Any confidential information deemed by the Company, in its sole discretion, to be appropriate to share, will only be transmitted to the requesting party after receipt of a fully executed Stage 3 Mutual Confidentiality and Non-Disclosure Agreement ("NDA"). See Appendix E.

1.5.5 Except as expressly permitted and in the manner prescribed in the Procedures Manual, any unsolicited contact by a Proposer or prospective Proposer with personnel of the Company pertaining to this RFP is prohibited.

1.6 Company Contact for Proposals

The primary contact for this RFP is:

Jasmine Wong
Energy Contract Manager
Hawaiian Electric Company, Inc.

RFP Email Address: oahurenewablerfp@hawaiianelectric.com

1.7 Proposal Submission Requirements

1.7.1 All Proposals must be prepared and submitted in accordance with the procedures and format specified in the RFP. Proposers are required to respond to all questions and provide all information requested in the RFP, as applicable, and only via the communication methods specified in the RFP.

1.7.2 Detailed requirements regarding the form, submission, organization and information for the Proposal are set forth in Chapter 3 and Appendix B.

1.7.3 Proposals must not rely on any information that is not contained within the Proposal itself in demonstrating compliance for any requirement in this RFP.

1.7.4 In submitting a Proposal in response to this RFP, each Proposer certifies that the Proposal has been submitted in good faith and without fraud or collusion with any other unaffiliated person or entity. The Proposer shall acknowledge this in the Response Package submitted with its Proposal. Furthermore, in executing the NDA provided as Appendix E, the Proposer agrees on behalf of its Representatives (as defined in the NDA) that the Company's negotiating positions will not be shared with other Proposers or their respective Representatives.

In addition, in submitting a Proposal, a Proposer will be required to provide Company with its legal counsel's written certification in the form attached as Appendix B, Attachment 1 certifying in relevant part, that irrespective of any Proposer's direction, waiver, or request to the contrary, the attorney will not share a Proposer's confidential information associated with such Proposer with others, including, but not limited to, such information such as a Proposer's or Company's negotiating positions. If legal counsel represents multiple unaffiliated Proposers whose Proposals are selected for the Final Award Group, such counsel will also be required to submit a similar certification at the conclusion of contract negotiations that he or she has not shared a Proposer's confidential information or the Company's confidential information associated with such Proposer with others, including but not limited to, such information as a Proposer's or Company's negotiating positions.

1.7.5 All Proposals must be submitted via the Electronic Procurement Platform by 2:00 pm Hawaiʻi Standard Time ("HST") on the respective Proposal Due Date shown in the RFP Schedule in Section 3.1, Table 2. No hard copies of these Proposals will be accepted by the Company.

It is the Proposer's sole responsibility to ensure that complete and accurate information has been submitted on time and consistent with the instructions of this RFP. With this assurance, the Company shall be entitled to rely upon the completeness and accuracy of every Proposal. Any errors identified by the Proposer or Company after the Proposal Due Date has passed may jeopardize further consideration and success of the Proposal. If an error or errors are later identified, the Company, in consultation with the Independent Observer, may permit the error(s) to be corrected without further revision to the Proposal, or may require the Proposer to adhere to terms of the Proposal as submitted without correction. Additionally, and in the Company's sole discretion, if such error(s) would materially affect the Priority List or Final Award Group, the Company reserves the right, in consultation with the Independent Observer, to remove or disqualify a Proposal upon discovery of the material error(s). The Proposer of such Proposal shall bear the full responsibility for such error(s) and shall have no recourse against the Company's decision to address Proposal error(s), including removal or disqualification. The Energy Contract Manager, in consultation with the Independent Observer, will confirm that all Proposals were submitted by the respective Proposal Due Dates shown in Section 3.1, Table 2. The Electronic Procurement Platform automatically closes to further submissions after the IPP Proposal Due Date shown in Section 3.1, Table 2.

1.8 Proposal Fee

1.8.1 IPP and Affiliate Proposers are required to tender a non-refundable Proposal Fee of $10,000 for each Proposal submitted.

1.8.2 Proposers may submit up to three (3) variations of their Proposal, one of which is the base variation of the Proposal, under a single Proposal Fee

1.8.3 Variations of GCOD,[22] pricing terms, Facility size or with/without storage (solar energy must include storage) can be offered. In addition to the targeted GCOD, as indicated in Sections 1.2.16 and 1.2.17, Proposers for firm renewable generation must include at least one (1) variation that indicates the earliest possible GCOD for the proposed Project as part of the Proposal. Variations which propose a different Site or different generation technology will not be considered and will be deemed a separate Proposal, and a separate Proposal Fee must be paid for each such Proposal. All unique information for each variation of a Proposal, no matter how minor such variation is, must be clearly identified and separated by following the instructions in Appendix B pertaining to "(Optional) Minor Proposal Variations".

1.8.4 The Proposal Fee must be in the form of a cashier's check from a U.S.-chartered bank made payable to "Hawaiian Electric Company, Inc." and must be delivered and received

[22] Differing from the Stage 2 RFPs, GCOD is no longer evaluated as part of the non-price criteria; however, all GCODs must be no later than December 1, 2027 to meet the corresponding Eligibility Requirement in Section 4.2.

by the Company by 2:00 pm (HST) on the respective Proposal Due Date shown in the RFP Schedule in Section 3.1, Table 2. The cashier's check should include a reference to the Proposal(s) for which the Proposal Fee is being provided. Proposers must identify in the Proposal Response Package (instructions in Appendix B, Section 1.3.1) the delivery information for its Proposal Fee. Proposers are strongly encouraged to utilize a delivery service method that provides proof of delivery to validate delivery date and time.

If the Proposal Fee is delivered by U.S. Postal Service (with registered, certified, receipt verification), the Proposer shall address it to:

Jasmine Wong
Energy Contract Manager
Hawaiian Electric Company, Inc.
Mail Code AL12-IU
PO Box 2750
Honolulu, Hawaiʻi 96840

If the Proposal Fee is delivered by other courier services, the Proposer shall address it to:

Hawaiian Electric Company, Inc.
Ward Receiving
Attention: Jasmine Wong, Energy Contract Manager
Mail Code AL12-IU
799 S. King St.
Honolulu, Hawaiʻi 96813

Due to coronavirus prevention measures, in-person delivery of Proposal Fees by Proposers will not be allowed.

1.9 Procedures for any Hawaiian Electric Proposal or Affiliate Proposal

1.9.1 The Competitive Bidding Framework allows the Company the option to offer a Self-Build Proposal in response to this RFP ("Hawaiian Electric Proposal"). Accordingly, the Company must follow certain requirements and procedures designed to safeguard against and address concerns associated with: (1) preferential treatment of the Hawaiian Electric Proposal or members, agents, or consultants of the Company formulating the Hawaiian Electric Development Team; and (2) preferential access to proprietary information by the Hawaiian Electric Development Team. These requirements are specified in the Code of Conduct required under the Framework and implemented by certain rules and procedures found in the Procedures Manual submitted with this RFP and attached as Appendix C. The Code of Conduct will apply to this RFP, regardless of whether the Company submits a Hawaiian Electric Proposal.

The Competitive Bidding Framework also allows Affiliates of the Company to submit Proposals[23] to RFPs issued by the Company. All Hawaiian Electric Proposals and

[23] A Proposal will also be treated as an Affiliate Proposal if the Affiliate is a partner for the Proposal.

Affiliate Proposals are subject to the Company's Code of Conduct and the Procedures Manual. Affiliate Proposals are also subject to any applicable Affiliate Transaction Requirements issued by the PUC in Decision and Order No. 35962 on December 19, 2018, and subsequently modified by Order No. 36112, issued on January 24, 2019, in Docket No. 2018-0065. Affiliate Proposals will be treated identically to IPP Proposals and must be submitted electronically through the Electronic Procurement Platform by the Hawaiian Electric and Affiliate Proposal Due Date in RFP Section 3.1, Table 2.

1.9.2 The Company will require that the Hawaiian Electric Proposal(s) and Affiliate Proposals be submitted electronically through the Electronic Procurement Platform. Hawaiian Electric and Affiliate Proposals will be due a minimum of one (1) day before other Proposals are due. A Hawaiian Electric and Affiliate Proposal will be uploaded into the Electronic Procurement Platform in the same manner Proposals from other Proposers are uploaded. The Energy Contract Manager, in consultation with the Independent Observer, will confirm that the Hawaiian Electric and Affiliate Proposals are timestamped by the Hawaiian Electric and Affiliate Proposal Due Date found in RFP Section 3.1, Table 2.

1.9.3 Detailed requirements for a Hawaiian Electric Proposal can be found in Appendix G. These requirements are intended to provide a level playing field between Hawaiian Electric Proposals and third-party Proposals. Except where specifically noted, a Hawaiian Electric Proposal must adhere to the same price and non-price Proposal requirements as required of all Proposers, as well as certain Stage 3 Contract requirements, such as milestones and liquidated damages, as described in Appendix G. The non-negotiability of the Performance Standards shall apply to any Hawaiian Electric Proposal to the same extent it would for any other Proposal. Notwithstanding the fact that it will not be required to enter into a Stage 3 Contract with the Company, a Hawaiian Electric Proposal will be required to note its exceptions, if any, to the Stage 3 Contract in the same manner required of other Proposers, and will be held to such modified parameters if selected. In addition to its Proposal, the Hawaiian Electric Development Team will be required to submit the Hawaiian Electric Development Team Certification Form provided as Attachment 1 of Appendix G, acknowledging it has followed the rules and requirements of the RFP to the best of its ability and has not engaged in any collusive actions or received any preferential treatment or information providing an impermissible competitive advantage to the Hawaiian Electric Development Team over other Proposers responding to this RFP, as well as adherence to Stage 3 Contract terms and milestones required of all Proposers and the Hawaiian Electric Proposal's proposed cost protection measures.

The cost recovery methods between a regulated utility proposal and IPP proposals are fundamentally different due to the business environments they operate in. As a result, the Company has instituted a process to compare the two types of Proposals for the initial evaluation of the price related criteria on a 'like' basis through comparative analysis.

At the core of a Hawaiian Electric Proposal are its total project capital cost and any associated annual O&M costs. During the RFP's initial pricing evaluation step, these capital costs[24] and O&M costs will be used in a revenue requirement calculation to determine the estimated revenues needed from customers which would allow the Company to recover the total cost of the project. The Hawaiian Electric Proposal revenue requirements are then used to determine a levelized energy price ("LEP" in \$/MWh), which will then be used for comparison to IPP and any Affiliate Proposals (see Section 4.4.1).

The Company, in conjunction with the Independent Observer, may also conduct a risk assessment of the Hawaiian Electric Proposal to ensure an appropriate level of customer cost protection measures are included in such Proposal.

If the Hawaiian Electric Proposal is not included in any shared savings mechanism for this RFP pre-approved by the PUC, the Hawaiian Electric Proposal will be permitted to submit a shared savings mechanism with its Proposal to share in any cost savings between the amount of cost bid in the Hawaiian Electric Proposal and the actual cost to construct the Project. If the Hawaiian Electric Proposal is selected to the Final Award Group, the proposed shared savings mechanism will need to be approved by the PUC. Submission of a shared savings mechanism is not required and will not be considered in the evaluation of the Hawaiian Electric Proposal.

1.10 Dispute Resolution Process

1.10.1 If disputes arise under the RFP, the provisions of Section 1.10 and the dispute resolution process established in the Framework will control. See Part V of the Framework.

1.10.2 Proposers who challenge or contest any aspect of the RFP process must first attempt to resolve their concerns with the Company and the Independent Observer ("Initial Meeting"). The Independent Observer will seek to work cooperatively with the parties to resolve any disputes or pending issues and may offer to mediate the Initial Meeting to resolve disputes prior to such issues being presented to the PUC.

1.10.3 Any and all disputes arising out of or relating to the RFP which remain unresolved for a period of twenty (20) days after the Initial Meeting takes place may, upon the agreement of the Proposer and the Company, be submitted to confidential mediation in Honolulu, Hawaiʻi, pursuant to and in accordance with the Mediation Rules, Procedures, and Protocols of Dispute Prevention Resolution, Inc. ("DPR") (or its successor) or, in its absence, the American Arbitration Association then in effect ("Mediation"). The Mediation will be administered by DPR. If the parties agree to submit the dispute to Mediation, the Proposer and the Company shall each pay fifty percent (50%) of the cost of the Mediation (i.e., the fees and expenses charged by the mediator and DPR) and shall otherwise each bear their own Mediation costs and attorney's fees.

1.10.4 If settlement of the dispute is not reached within sixty (60) days after commencement of the Mediation, or if after the Initial Meeting, the parties do not agree to submit any

[24] Hawaiian Electric Proposals will be required to provide a table identifying project costs by year. These capital costs should be all inclusive, including but not limited to costs associated with equipment, Engineering, Procurement, and Construction, interconnection, overhead, and Allowance for Funds Used During Construction.

unresolved disputes to Mediation, then as provided in the Framework, the Proposer may submit the dispute to the PUC in accordance with the Framework.

1.10.5 In accordance with the Framework, the PUC will serve as the arbiter of last resort for any disputes relating to this RFP involving Proposers. The PUC will use an informal expedited dispute resolution process to resolve the dispute within thirty (30) days, as described in Parts III.B.8 and V of the Framework.[25] There will be no right to hearing or appeal from this informal expedited dispute resolution process.

1.10.6 By submitting a Proposal in response to this RFP, each Proposer expressly agrees that if it initiates a dispute resolution process for any dispute or claim submitted in violation of or arising under or relating to this RFP (e.g., a court proceeding, arbitration, etc.), other than as permitted by the Framework and Section 1.10 of this RFP, such dispute shall be dismissed with prejudice and the Proposer filing such dispute or claim shall be responsible for any and all attorneys' fees and costs that may be incurred by the Company or the PUC in order to resolve such claim.

1.11 No Protest or Appeal

Subject to Section 1.10, no Proposer or other person will have the right to protest or appeal to any court or other dispute resolution organization, any award, non-award or disqualification of a Project made by the Company or any decision by the Commission made pursuant to Section 1.10.5.

By submitting a Proposal in response to the RFP, the Proposer expressly agrees to the terms and conditions set forth in this RFP.

1.12 Modification or Cancellation of the Solicitation Process

1.12.1 Unless otherwise expressly prohibited, the Company may, at any time up to the final execution of a Stage 3 Contract, as may be applicable, in consultation with the Independent Observer, postpone, withdraw, and/or cancel any requirement, term, or condition of this RFP, including deferral of the award or negotiation of any contract, and/or cancellation of the award all together, all of which will be without any liability to the Company.

1.12.2 The Company may modify this RFP subject to requirements of the Framework, whereby the modified RFP will be reviewed by the Independent Observer and submitted to the PUC thirty (30) days prior to its issuance, unless the PUC directs otherwise. See Framework Part IV.B.10. The Company will follow the same procedure with regard to

[25] The informal expedited dispute resolution process does not apply to PUC review of contracts that result from the RFP. See Decision and Order No. 23121 at 34-35. Further, the informal expedited dispute resolution process does not apply to the Framework's process relating to issuance of a draft and final RFP, and/or to the PUC approval of the RFP because: (1) the Framework (and the RFP) set forth specific processes whereby interested parties may provide input through the submission of comments; and (2) the Framework's dispute resolution process applies to "Bidders" and there are no "Bidders" at this stage in the RFP process.

any potential postponement, withdrawal, or cancellation of the RFP or any portion thereof.

Chapter 2: Resource Needs and Requirements

2.1 Performance Standards

Proposals must meet the Performance Standards and attributes set forth in this RFP, and the Performance Standards and requirements set forth in the respective model Stage 3 Contract. This RFP and the applicable Stage 3 Contract set forth the minimum requirements that all Proposals must satisfy to be eligible for consideration in this RFP. Additional Performance Standards may be required based on the results of the IRS. The Company has not yet fully adopted IEEE 2800-2022 as it was recently published. However, the inverters being procured in this RFP may need to conform to certain functions of IEEE 2800-2022 as identified in studied completed within this RFP, or in the future operations of the project. The interconnection study will incorporate IEEE 2800 to the extent applicable to our island systems.

2.1.1 Storage inverters (i.e., Paired Projects and Standalone Storage Projects) must be able to operate in grid-forming mode[26] as defined in the applicable Stage 3 Contract.

2.1.2 Black start capability[27] is preferred, but not required, for all Projects. Proposals electing to provide black start capability will need to identify[28] any incremental costs to enable their facility to be black start capable, if not already enabled.

2.1.3 For Proposals with energy storage components, the functionality and characteristics of the storage must be maintained throughout the term of the Stage 3 Contract since the Company will rely on the capacity the energy storage components provide. To be clear, Proposers may not propose any energy storage degradation for either capacity or efficiency in their Proposals. Ensuring that there is no degradation in storage capacity or efficiency over the term of the PPA can be accomplished in a number of ways, including overbuilding or pricing in replacement components. The particular manner in which this requirement is achieved is ultimately up to the Proposer to include in its Proposal. Note that selected Projects shall not sell energy to off-takers or third parties. The Companies are not seeking proposals for microgrids and will not pay for availability, energy, capacity or any other service if a Project is being operated in a microgrid mode. However, in the event that a landowner requires a Project have the capability to provide

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[26] While not required, generation-only wind Proposals are also encouraged to propose Projects with grid-forming capabilities.

[27] Black start capability refers to the Facility's ability to start itself and provide power to the Company's grid without relying on any services or energy from the Company's grid in order to assist the grid in recovering from a total or partial shutdown. During such a total or partial shutdown of the grid, the Project may experience step changes in load and other transient and dynamic conditions as it picks up load without support from other resources on the grid during start-up (if the Project remains connected) or while connecting to the loads the Project is picking up (not the start-up and connecting of the Facility itself).

[28] If black start is not already enabled for the Proposal, any additional costs necessary to enable black start will be identified in the submission instructions defined in Appendix B.

such services to the landowner, the Companies require that Proposals being used for microgrid applications must operate in a grid-connected mode as its primary function but may operate from grid-connected mode to island mode at the Company's sole discretion. Microgrid generators in island mode must return to grid-connected mode at the Company's sole discretion.

2.2 Transmission System Information

As specified in Section 1.2.10, Projects must interconnect to the Hawaiian Electric System at the 138 kV transmission-level or 46 kV sub-transmission-level. Proposers must inquire about the potential available MW capacity of the line at the specific location at which they propose to interconnect, or about the available MW capacity and substation conditions of the offered Company substation at which they propose to interconnect.[29] Proposers may also request a high-level map identifying the offered 138 kV transmission-level line, 46 kV sub-transmission-level line, and the offered substations. Requests shall be directed to the RFP Email Address in Section 1.6 after the execution of the NDA as specified in Section 3.12.1.

Proposers should perform their own evaluation of project locations, and the Company does not guarantee any project output or ability to connect based on information provided prior to the completion of an IRS. For example, an IRS may find that a project causes an effective grounding issue, requiring additional grounding equipment to mitigate the issue.

Proposers may propose Project sizes greater than the potential available MW capacities, but such proposals are expected to require reconductoring of existing lines, the addition of transmission lines, the rebuild or expansion of an existing substation and/or other infrastructure, which would be at the Proposer's cost and must be able to be completed in time for the Project to reach its bid GCOD. Proposers seeking to propose Projects with system upgrades must seek feedback from the Company prior to bid submittal, as there may be reliability limitations on certain facilities that do not allow capacity increases. Proposers must include and reflect all system upgrade costs, schedule and timeline impacts, and design impacts in their Proposal. Further, Projects may require capacity reduction if identified in the detailed IRS.

2.2.1 Process for developers electing to interconnect to non-offered 138 kV transmission lines or substations or 46 kV sub-transmission lines: Proposers proposing Projects to non-offered locations should submit a proposed interconnection location, project size, and other available project details. The Company will review the interconnection location and project size to provide high-level requirements for interconnection of the project. The Proposers shall then use this information, along with unit pricing in Appendix H to include system upgrade costs in their proposal. Appendix H does not include an exhaustive list of estimates, and Proposers may need to develop their own estimates for work that is not covered. Proposers are ultimately responsible for development of their pricing to incorporate these system upgrades, and may submit follow-up questions to the Company as necessary to develop their cost estimate.

[29] Responses will be provided upon the execution of an NDA with the Company as specified in Section 3.12.1.

The Company re-iterates the reason for providing an offered 46 kV and 138 kV interconnection list is to provide a streamlined process for developers, as more upfront information is provided and locations were based on a preliminary feasibility assessment. Proposers should anticipate the following system upgrades for interconnections to non-offered sites:

2.2.1.1 Interconnection to a non-offered 46 kV or 138 kV line or for projects larger than the available MW capacity on offered 46 kV or 138kV lines: Lines that have been offered for interconnection are known to have available MW capacity to allow project interconnections. However, non-offered line interconnections have a high likelihood of requiring reconductoring and/or new transmission lines to the proposer's switching station. In addition, new transmission lines require terminations at the nearest or most feasible transmission substation, which may also trigger rebuild, reconfiguration, and/or expansion to accommodate the line interconnection.

2.2.2 A detailed IRS, when performed, may reveal other adverse system impacts that may further limit a Project's contract capacity or require interconnection upgrades.

2.3 Interconnection to the Company System

2.3.1 The Proposer must provide information pertaining to the design, development, and construction of the Interconnection Facilities. Interconnection Facilities includes both: (1) Seller-Owned Interconnection Facilities; and (2) Company-Owned Interconnection Facilities. All Proposals must include a description and conceptual or schematic diagrams of the Proposer's plan to transmit power from the Facility to the Company's System. The proposed Interconnection Facilities must be compatible with the Company's System. In the design, Projects must adequately consider Company requirements to address impacts on the performance, safety, and reliability of the Company System.

In addition to the Performance Standards and findings of the IRS, the design of the Interconnection Facilities, including power rating, POI with the Company's System, and scheme of interconnection, must meet Company standards.

To facilitate Proposers receiving additional information on the Company's required specifications and procedures early in the RFP process, the Company will offer its Engineer, Procure, Construct Specifications for Hawaiian Electric Power Lines and Substations ("EPC Specifications")[30] to Proposers if requested via the communication method identified in Section 1.6 and upon the execution of an NDA as specified in Section 3.12.1 and the execution of a separate Confidentiality, Waiver, and Hold Harmless Agreement with the Company provided as Attachment 1 of Appendix E. These EPC Specifications are intended to illustrate the scope of work typically required to

[30] The Company's EPC Specifications are currently being updated, but the Company will provide these in draft form. The draft is currently being reviewed to ensure consistency between all documents, but the drafts should provide useful guidance to assist with the Proposal development. The Company will not be responsible for updates made to the EPC Specifications after transmittal to a Proposer, even if such update results in the need for a Proposer to make necessary revisions to its designs and/or plans.

administer and perform the design and construction of a Hawaiian Electric substation and power line.

The Company will also make available typical substation layouts and typical transmission and distribution estimating assumptions to assist with Proposal estimations and familiarize Proposers with the Company's engineering expectations for the Proposer's Interconnection Facilities. The layouts and design assumptions may not reflect the exact requirements of a Proposer's Project but should provide useful guidance to assist with their Proposal development. To request these layouts and assumptions, Proposers may submit a request via the communication method identified in Section 1.6 upon the execution of an NDA as specified in Section 3.12.1.

The most updated and applicable Company standards and specifications will also be provided later to Projects that are selected to the Final Award Group and continue through negotiations. At that time, if the EPC Specifications have since been updated, the Company will also make available an updated version.

Past PPAs executed with the Company are filed with the PUC and are publicly available on the PUC's Document Management System website. Attachment G and Matrix G-1 of recently filed PPAs contain summarized total estimated interconnection cost information of the Company-Owned Interconnection Facilities and the identification of substation responsibilities. In addition, on March 31, 2022, the Company's Key Performance Metrics Interconnection Experience website went live. The website contains a list of projects and their estimated and actual interconnection costs for the portions of interconnection built by the Company. These resources may also aid Proposers in estimating the costs of their Interconnection Facilities. However, the Company notes that each Project and point of interconnection is unique and it is the Proposer's responsibility to ensure it conducts proper due diligence to determine the proper interconnection requirements for its Project. Proposers should therefore not assume that an interconnection configuration and associated interconnection costs for a prior project is suitable and appropriate for its proposed Project.

2.3.1.1 Interconnection Facilities must be designed such that it meets or exceeds the applicable single line diagram in Appendix H. Attachments 5 through 12 of Appendix H may be requested via the communication method identified in Section 1.6 upon the execution of an NDA as specified in Section 3.12.1.

2.3.2 Tariff Rule No. 19 establishes provisions for Interconnection and Transmission Upgrades and can be found at https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric _rules/19.pdf. The tariff provisions are intended to simplify the rules regarding who pays for, installs, owns, and operates Interconnection Facilities in the context of competitive bidding. As stated in the tariff, in the event there is any conflict between the tariff and this RFP, the provisions of this RFP shall prevail. Proposers shall be required to build the Company-Owned Interconnection Facilities, including the switching station and line work, except for any work in the Company's existing energized facilities and the final tap as described in Appendix H. Construction of Company-Owned Interconnection Facilities by the Proposer must comply with industry standards, laws, rules and licensing requirements, as well as the Company's specific construction standards and procedures that the Company will provide upon request. (See Section 2.3.1.)

2.3.3 The Proposer shall be responsible for all costs required to interconnect a Project to the Company's System, including all Seller-Owned Interconnection Facilities and Company-Owned Interconnection Facilities, regardless of who is responsible for building such facilities. Unless otherwise explicitly stated in this RFP, a Proposer must assume that it is responsible for all interconnection costs, and should not assume that any portion of such interconnection costs is for a System upgrade allocable to the Company.

2.3.4 Proposers are required to include in their pricing proposal all costs for interconnection and equipment expected to be required between their Facility and their proposed POI. Appendix H includes information related to Company-Owned Interconnection Facilities and costs that may be helpful to Proposers. Selected Proposers shall be responsible for the actual final costs of all interconnection costs for its Project including Seller-Owned Interconnection Facilities and Company-Owned Interconnection Facilities (see Appendix H), whether or not such costs exceed the costs set forth in a Proposer's Proposal. No adjustments will be allowed to the proposed price in a Proposal if actual costs for Interconnection Facilities exceed the amounts proposed.

2.3.5 Proposers are required to account for all costs for distribution-level service connection for station power in their pricing proposal.

2.3.6 All Projects will be screened for general readiness to comply with the requirements for interconnection. Proposals selected to the Final Award Group will be subject to Section 5.1. Proposals selected to the Final Award Group may be subject to further study in the form of an IRS. The IRS process is further described in Section 5.1. The results of the completed IRS or as identified through the Detailed Evaluation process, as well as any mitigation measures identified, will be incorporated into the terms and conditions of a final executed Stage 3 Contract.

2.3.7 To maintain the integrity of the transmission system, Proposals will only be allowed to interconnect to the following:

2.3.7.1 **Existing 138 kV substations, as provided in Table 1 below.** Available terminations are 138 kV line terminations, which may be used for interconnecting up to 142 MW[31] of generation. Note that each termination is required to be a Breaker-and-a-Half ("BAAH") configuration and may require additional land to complete the expansion. These substations have space available and the necessary infrastructure to meet the transmission planning criteria for firm generation resources.

[31] Additional equipment upgrades may be required to allow 142 MW of generation at each termination.

Table 1
Potential 138 kV Substation Points of Interconnection

Voltage	Location	Available Terminations	Comments
138 kV	Ewa Nui Substation	2	2 BAAH bay expansion required
138 kV	CEIP Substation	1	1 BAAH bay expansion required. Routing new 138kV interconnecting line into the sub will be challenging due to future planned buildout around existing substation.
138 kV	Hoohana Substation	3	Assumes substation is built. 1 termination available as currently designed. Expansion of 2 additional BAAH bays to terminate Kahe-Halawa 2 138 kV line is required to interconnect the 2nd and 3rd terminations. Generation interconnected is limited if connected to Kahe-Halawa 1 only.
138 kV	Kahe Substation	3	3 BAAH bay expansion required
138 kV	AES Substation	2	1 BAAH bay currently in use by existing IPP. 1 additional BAAH bay requires substation perimeter expansion.
138 kV	Koolau Substation	1	Space available for one new interconnecting line (two breakers need to be installed in existing BAAH bay). Routing new 138kV interconnecting line into the sub will be challenging due to future planned buildout around existing substation
138 kV	Waiau Power Plant	4	Available if using existing generation interconnections (e.g., existing units are removed).

2.3.7.2 **Existing 138 kV lines running in parallel.** Proposers shall provide a new BAAH switching station to interconnect transmission lines and the new generating resource. Existing 138 kV lines meeting this requirement are:

1) Ewa Nui 1 & 2, between Ewa Nui substation and Waiau substation;

2) Waiau-Koolau 1 & 2, between Waiau substation and Koolau substation; and

3) Koolau-Pukele 1 & 2, between Koolau substation and Pukele substation.

Proposers must include the costs for use of the land and site preparation for a new switching station, as specified in Appendix H. The evaluation of these Projects is specified in Section 4.4.

2.3.7.3 **Existing 46 kV lines.** Proposers shall request available hosting capacity of subtransmission lines intended for interconnection. Generating resources added above available hosting capacity may be allowed, but will require upgrades if possible (e.g., reconductoring, equipment replacements, etc.) to existing infrastructure at the Proposer's cost.

2.3.7.3.1 Proposals for Firm renewable dispatchable generation Projects shall provide a new ring bus switching station to interconnect subtransmission lines and the new generating resource. The switching station must connect to two subtransmission lines.

2.3.7.3.2 Proposals for Variable Generation Projects, Paired Projects and Standalone Storage Projects may be tapped to subtransmission lines via a new interconnection.

Chapter 3: Instructions to Proposers

3.1 Schedule for the Proposal Process

Table 1 sets forth the proposed schedule for the proposal process (the "RFP Schedule"). The RFP Schedule is subject to PUC approval. The Company reserves the right to revise the RFP Schedule as necessary. Changes to the RFP Schedule prior to the RFP Proposal Due Date will be posted to the RFP website. Changes to the RFP Schedule after the Proposal Due Date will be communicated via Email to the Proposers and posted on the RFP website.

Table 2
Proposed RFP Schedule

Milestone	Schedule Dates
(1) Draft RFP filed	May 2, 2022
(2) Community Meeting	May 10, 2022
(3) Parties and Participants filed Comments by	June 2, 2022
(4) Community Meeting 2	July 12, 2022
(5) Technical Conference	August 5, 2022
(6) Order 38735 Issued	December 1, 2022
(7) Proposed Final RFP Filed	December 22, 2022
(8) Issue RFP	January 20, 2023[32]
(9) Hawaiian Electric and Affiliate Proposal Due Date	April 19, 2023 at 2:00 pm HST
(10) IPP Proposal Due Date	April 20, 2023 at 2:00 pm HST
(11) Selection of Priority List	July 6, 2023
(12) Hawaiian Electric and Affiliate BAFOs Due	July 13, 2023
(13) IPP BAFOs Due	July 14, 2023
(14) Selection of Final Award Group	October 27, 2023
(15) IRS and Contract Negotiations Begin	November 3, 2023

3.2 Company RFP Website/Electronic Procurement Platform

3.2.1 The Company has established a website for general information to share with potential Proposers. The RFP website is located at the following link:

www.hawaiianelectric.com/OahuStage3RFP

The Company will provide general notices, updates, schedules and other information on the RFP website throughout the process. Proposers should check the website frequently to stay abreast of any new developments. This website will also contain the link to the Electronic Procurement Platform employed by the Company for the receipt of Proposals.

"Sourcing Intelligence" developed by PowerAdvocate[33] is the Electronic Procurement Platform that the Company has licensed and will utilize for the receipt of Proposals in this RFP. Proposers who do not already have an existing account with PowerAdvocate and who intend to submit a Proposal for this RFP will need to register as a "Supplier" with PowerAdvocate.

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[32] This date and all subsequent dates in the proposed final schedule are dependent on any further guidance to be set by the PUC.

[33] PowerAdvocate became part of Wood Mackenzie in 2021, but web addresses and support email addresses still reference PowerAdvocate.

3.2.2 There are no license fees, costs, or usage fees to Proposers for the use of the Electronic Procurement Platform.

See Appendix D for user information on and screenshots of PowerAdvocate's Sourcing Intelligence procurement platform.

3.3 Information Exchange

Virtual Community Meetings were held on May 10, 2022 and July 12, 2022. A virtual Technical Status Conference was also held on August 5, 2022. The Company has also been fielding questions from prospective Proposers via the RFP Email Address and posting applicable Q&As on the RFP Website since April 2022.

Prospective Proposers may submit written questions regarding the RFP and their Proposal to the RFP Email Address set forth in Section 1.6. Proposers should include the Independent Observer when submitting questions to the RFP Email Address. In addition to the Independent Observer who should be included on all correspondence to the Company, Proposers should also include the Independent Engineer on any questions to the RFP Email Address of a technical nature. The Company will endeavor to address all questions. Questions and responses that might be helpful to other prospective Proposers will be shared via a Q&A section on the RFP website. Prospective Proposers should review the RFP website's Q&A section prior to submission of their Proposal. Duplicate questions will not be answered.

3.4 Preparation of Proposals

3.4.1 Each Proposer shall be solely responsible for reviewing the RFP (including all attachments and links) and for thoroughly investigating and informing itself with respect to all matters pertinent to this RFP, the Proposer's Proposal, and the Proposer's anticipated performance under the applicable Stage 3 Contract. It is the Proposer's responsibility to ensure it understands all requirements of the RFP, to seek clarification if the RFP's requirements or Company's request is not clear, and to ask for any confirmation of receipt of submission of information. Under Section 1.7.5, the Proposer is solely responsible for all errors in its Proposal(s). The Company has no obligation to inform the Proposer of any error, and the Company will not accept any explanation by a Proposer that it was incumbent on the Company to catch any error.

3.4.2 Proposers shall rely only on official information provided by the Company in this RFP when preparing their Proposal. The Company will rely only on the information included in the Proposals, and additional information solicited by the Company to Proposers in the format requested, to evaluate the Proposals received. Evaluation will be based on the stated information in this RFP and on information submitted by Proposers in response to this RFP. Proposals must clearly state all capabilities, functionality and characteristics of the Project; must clearly detail plans to be performed; must explain applicability of information; and must provide all referenced material if it is to be considered during the Proposal evaluation. Referencing previous RFP submissions or projects for support will not be considered. Proposers should not assume that any previous RFP decisions or preferences will also apply to this RFP.

3.4.3 Each Proposer shall be solely responsible for, and shall bear all of its costs incurred in the preparation of its Proposal and/or its participation in this RFP, including, but not limited to, all costs incurred with respect to the following: (1) review of the RFP documents; (2) information conference participation; (3) third-party consultant consultation; and (4) investigation and research relating to its Proposal and this RFP. The Company will not reimburse any Proposer for any such costs, including the selected Proposer(s).

3.4.4 Each Proposal must contain the full name and business address of the Proposer and must be signed by an authorized officer or agent[34] of the Proposer.

3.5 Organization of the Proposal

3.5.1 The Proposal must be organized as specified in Appendix B. It is the Proposer's responsibility to ensure the information requested in this RFP is submitted and contained within the defined proposal sections as specified in Appendix B.

3.5.2 The Proposer must contact the Company to request any alterations from the proposal format if the Proposer feels the format will not allow the pricing, capabilities, functionality or characteristics of the Project to be captured in the Proposal. The Proposer must provide sufficient time for the Company to respond with guidance as to what alterations will be allowed.

3.6 Proposal Limitations

In submitting a Proposal, Proposers expressly acknowledge and agree that Proposals are submitted subject to the following limitations:

The RFP does not commit or require the Company to award a contract, pay any costs incurred by a Proposer in the preparation of a Proposal, or procure or contract for products or services of any kind whatsoever. The Company reserves the right, in consultation with the Independent Observer, to accept or reject, in whole or in part, any or all Proposals submitted in response to this RFP, to negotiate with any or all Proposers eligible to be selected for award, or to withdraw or modify this RFP in whole or in part at any time.

- The Company reserves the right, in consultation with the Independent Observer, to request additional information from any or all Proposers relating to their Proposals or to request that Proposers clarify the contents of their Proposals. Proposers who are not responsive to such information requests may be eliminated from further consideration upon consultation with the Independent Observer.

[34] Proposer's officer or agent must be authorized to sign the Proposal. Such authorization must be in writing and may be granted via Proposer's organizational documents (i.e., Articles of Incorporation, Articles of Organization, By-laws, etc.), resolution, or similar documentation.

- The Company reserves the right, in consultation with the Independent Observer, to solicit additional Proposals from Proposers after reviewing the initial Proposals. Other than as provided in this RFP, no Proposer will be allowed to alter its Proposal or add new information to a Proposal after the Proposal Due Date.

- All material submitted in response to this RFP will become the sole property of the Company, subject to the terms of the NDA.

Proposers understand and agree that if its Proposal is selected by the Company for the Final Award Group, such selection shall in no way constitute the Company's confirmation that a Proposer's Project will meet the requirements under this RFP, e.g., that the Project's proposed interconnection is feasible and will meet the Company's requirements. The Proposer is ultimately responsible for ensuring that its Project meets the technical requirements specified in this RFP, and if the parties reach agreement on a Stage 3 Contract, the requirements specified in the Stage 3 Contract.

3.7 Proposal Compliance and Bases for Disqualification

Proposers may be deemed non-responsive and/or Proposals may not be considered for reasons including, but not limited to, the following:

- Any unsolicited contact by a Proposer or prospective Proposer with personnel of the Company pertaining to this RFP as described in Section 1.5.5.

- Any illegal or undue attempts by or on behalf of the Proposer or others to influence the Proposal Review process.

- The Proposal does not meet one or more of the Eligibility Requirements specified in Section 4.2.

- The Proposal does not meet one or more of the Threshold Requirements specified in Section 4.3.

- The Proposal is deemed to be unacceptable through a fatal flaws analysis as described in Section 4.4.2.

- The Proposer does not respond to a Company request for additional information to clarify the contents of its Proposal within the timelines specified by the Company.

- The Proposal contains misrepresentations or errors.

3.8 Stage 3 Contracts

3.8.1 The Stage 3 Contract for any PV Paired Project selected under this RFP will be in the form of the Company's PV+BESS RDG PPA attached as Appendix J.

The Stage 3 Contract for any wind Generation Project or wind Paired Project selected under this RFP will be in the form of the Company's Wind+BESS RDG PPA attached as Appendix K.

The Stage 3 Contract for any Firm Project selected under this RFP will be in the form of the Company's Firm PPA attached as Appendix L.

3.8.2 The Stage 3 Contract for Standalone Storage Projects selected under this RFP will be in the form of the Company's ESPA, attached as Appendix M.

3.8.3 If selected, any Affiliate Proposers will be required to enter into the applicable Stage 3 Contract with the Company.

3.8.4 If selected, a Hawaiian Electric Development Team will not be required to enter into a Stage 3 Contract with the Company. However, the Hawaiian Electric Development Team will be held to the proposed modifications to the applicable Stage 3 Contract, if any, it submits as part of the Hawaiian Electric Proposal in accordance with Section 3.8.6. Moreover, the Hawaiian Electric Proposal will be held to the same performance metrics and milestones set forth in the applicable Stage 3 Contract to the same extent as all Proposers, as attested to in the Hawaiian Electric Proposal's Appendix G, Attachment 1, Hawaiian Electric Development Team Certification submittal. If liquidated damages are assessed, they will be paid from shareholder funds and returned to customers through the Purchased Power Adjustment Clause or other appropriate rate adjustment mechanisms.

To retain the benefits of operational flexibility for a Company-owned facility, the Hawaiian Electric Proposal will be permitted to adjust operational requirements and performance metrics with the approval of the PUC. The process for adjustment would be similar to a negotiated amendment to a Stage 3 Contract with PUC approval.

3.8.5 In general, under the RDG PPA and ESPA, payment to the Seller consists of a Lump Sum Payment to cover the costs of the Project. For Firm Projects only, in addition to a Capacity Charge payment, the Company will allow developers to also include an additional Energy Charge payment component ($/MWh) to cover variable operations and maintenance costs that cannot be captured within the Capacity Charge payment component. In return for the payments, the Seller shall guarantee minimum performance and availability metrics to ensure that the Facility is maintained and available for energy, storage (if applicable) and dispatch, as well as provide an indication of the available energy in near real-time for the Company's dispatch. The Company shall not be obligated to accept, nor shall it be required to pay for, test energy generated by the Facility during acceptance testing or other test conditions.

3.8.6 The Performance Standards identified in Section 2.1 establish the minimum requirements a Proposal must satisfy to be eligible for consideration in this RFP. A proposed Facility's ability to meet these Performance Standards is both a Threshold Requirement and a Non-price evaluation criterion under Sections 4.3 and 4.4.2, respectively. As such, these Performance Standards are non-negotiable by any Proposer. As previously stated, if a Proposer proposes a technology that is not already represented in any model Stage 3

Contract, the terms of the applicable model Stage 3 Contract will be modified to address the specific technology and/or component. Proposers must provide documentation to support their requests for contract modifications. For example, for firm generation facilities, recognizing some firm technologies operate significantly differently, necessary modifications required for particular technologies will be permitted if Proposer provides technical specifications that support the need for such proposed modifications. Proposers may propose modifications to other sections of the model Stage 3 Contracts (see Section 3.8.8 below) but are encouraged to accept such terms as written in order to expedite the overall RFP process and potential contract negotiations. As a component of their respective Proposals, the Hawaiian Electric Development Team or any other Proposer who elects to propose modifications shall provide a Microsoft Word red-line version of the relevant document identifying specific proposed modifications to the model Stage 3 Contract language that the Proposer is agreeable to, as well as a detailed explanation and supporting rationale for each modification.

3.8.6.1 General comments, drafting notes and footnotes such as "parties to discuss," and reservation of rights to propose modifications at a later time, are unacceptable and will be considered non-responsive. Proposed modifications to any model Stage 3 Contract will be evaluated as a non-price evaluation criterion as further described in Section 4.4.2. In order to facilitate this process, the Company will make available electronic versions of the model Stage 3 Contracts on the RFP website and through the Electronic Procurement Platform for the RFP. Any proposed modifications to the model Stage 3 Contract will be subject to negotiation between the Company and the Final Award Group and should not be assumed to have been accepted either as a result of being selected to the Final Award Group or based on any previously executed PPA. As stated above, since general comments, drafting notes, and footnotes without accompanying specific proposed language modifications are unacceptable and non-responsive, the Company will not negotiate provisions simply marked by such general comments, drafting notes, and footnotes.

3.8.6.2 The Company has an interest in maintaining consistency for certain provisions of the Stage 3 Contracts, such as the calculation of availability and payment terms. Therefore, for such provisions, the Company will endeavor to negotiate similar and consistent language across Stage 3 Contracts for the Final Award Group.

3.8.7 Proposals that do not include specific proposed modifications to the attached model Stage 3 Contracts will be deemed to have accepted the model Stage 3 Contract in its entirety.

3.8.8 As stated in Section 3.8.6 above, Proposers may propose modifications to sections of the model Stage 3 Contracts. However, certain sections specified below in the various model Stage 3 Contracts are non-negotiable.

3.8.8.1 For the RDG PPAs, Performance Standards are non-negotiable. Also, as identified in the Schedule of Defined Terms in the RDG PPAs that contain an energy storage component under "BESS Allocated Portion of the Lump Sum Payment", the allocated portion of the Lump Sum Payment specified for energy storage for the Facility for determining liquidated damages is 50% and shall be a non-negotiable percentage in the RDG PPA.

Further, as stated in Section 3.13.2 below, Proposers shall not propose an amount lower than that set forth in the RDG PPA for Development Period Security and Operating Period Security.

3.8.8.2 For the Firm PPA, Performance Standards are non-negotiable, except as recognized in Section 3.8.6 above, and, as stated in Section 3.13.2 below, Proposers shall not propose an amount lower than that set forth in the Firm PPA for Development Period Security and Operating Period Security.

3.8.8.3 For the ESPA, Performance Standards are non-negotiable, and, as stated in Section 3.13.2 below, Proposers shall not propose an amount lower than that set forth in the ESPA for Development Period Security and Operating Period Security.

3.9 Pricing Requirements

3.9.1 Proposers must submit pricing for each of their variations associated with each Proposal (if variations as described in Section 1.8.2 and 1.8.3 are submitted). Proposers are responsible for understanding the terms of the applicable Stage 3 Contract. Pricing cannot be specified as contingent upon any other factor (e.g., changes to federal tax policy, assuming that all applicable federal tax credits are received, assuming that the Company will accept any proposed change to the applicable Stage 3 Contract).

3.9.2 Escalation in Lump Sum Payment or Capacity Charge payment pricing over the term of the Stage 3 Contract is prohibited.

3.9.3 Pricing information must only be identified within specified sections of the Proposal as instructed by this RFP's Appendix B (i.e., Proposal pricing information must be contained within defined Proposal sections of the Proposal submission). Pricing information contained anywhere else in a Proposal will not be considered during the evaluation process.

3.9.4 The Proposer's Response Package must include the following prices for each Proposal (and variation):

For IPP or Affiliate proposals:

- [For PV+BESS, Wind+BESS, and Standalone Storage Projects]
  - **Lump Sum Payment ($/year):** Payment amount for full dispatchability of the Facility. Payment will be made in monthly increments.
  - **Black Start ($)**: If not already black start enabled/capable, the incremental cost required for the Facility to enable black start or for the Facility to be black start capable.
- [For Firm Projects]
  - **Capacity Charge payment ($/kW/Month):** Payment for the capacity available to the Company's System from the Facility.
  - **Energy Charge payment ($/kWh)**: Payment for delivery of net energy sourced from the generation resource, if desired. As stated in Attachment J of the Firm PPA, the Energy Charge payment consists of two components: a

Fuel Component and a Variable O&M Component. No Energy Charge will be provided for any energy delivery that is sourced originally from the grid (Company's System). The Energy Charge may contain a Variable O&M Component; however, the Variable O&M Component must be guaranteed and not be tied to an index. The Variable O&M Component may include escalations; however, such escalation must be in the form of a guaranteed percentage.

- o **Heat Rate Curve (if applicable)**: A guaranteed heat rate curve specified as a three-term second-order polynomial relative to facility net MW output. This curve will be used to determine the variable cost of the fuel for a given MW output.

For Hawaiian Electric Proposals:

- **Total Project Capital Costs ($/year):** Total capital costs for the project (identified by year).
- **Annual O&M Costs ($/year):** Initial year operations and maintenance costs, annual escalation rate.
- **Annual Revenue Requirement ($/year):** Annual revenue requirements ("ARR") calculated for each year.
- [For Hawaiian Electric Firm Project Proposals]
  - o **Heat Rate Curve (if applicable)**: A guaranteed heat rate curve specified as a three-term second-order polynomial relative to facility net MW output. This curve will be used to determine the variable cost of the fuel for a given MW output.

See Appendix G for descriptions and detail on the Total Project Capital Costs, Annual O&M Costs, and ARR for Hawaiian Electric Proposals.

3.9.5 To allow Proposers to offer the most competitive pricing while offering protection during these times of market volatility, the Company will allow an indexed one-time capped pricing adjustment explained in Section 4.6.3 below.

3.10 Project Description

3.10.1 NEP and Capacity

3.10.1.1 Proposals utilizing the RDG PPA are required to provide a Net Energy Potential ("NEP") RFP Projection for the proposed Facility. The NEP RFP Projection represents the estimated annual net energy potential (in MWh) that could be produced by the Facility and delivered to the POI over a 10-year period with a probability of exceedance of 95%. The NEP RFP Projection represents the energy generated by the Facility from the renewable resource and delivered to the POI assuming all energy is directly exported to the POI in the moment it is generated (full dispatch during all production hours) and never in excess of the Contract Capacity. The NEP RFP Projection should ignore any contributions from the energy storage component of the Facility.[35] The NEP RFP Projection is independent of the actual dispatch of the Facility as dispatch is at the full discretion of the Company. The NEP RFP Projection should be reduced by anticipated maintenance and losses such as System degradation and balance of plant losses. The NEP RFP Projection will be used in the RFP evaluation process and therefore Proposers will be held to their provided value.[36] However, after selection to the Final Award Group and prior to the completion of the NEP Independent Engineering Estimate, the Company will allow the Proposer a one-time upward adjustment to its NEP RFP Projection of up to five percent (5%) above its original Proposal's NEP RFP Projection along with any proportioned change to its Lump Sum Payment as long as the Project's RDG PPA unit price does not change.

3.10.1.2 Proposals utilizing the Firm PPA are required to provide their Contract Firm Capacity which is the amount of MW of net dependable active power anticipated to be made available to Company from the Facility at the Metering Point subject to Company Dispatch upon Commercial Operations. Along with the Contract Firm Capacity, Proposers utilizing the Firm PPA should provide an anticipated maintenance schedule and level of reductions expected to the Contract Firm Capacity during maintenance. Proposals must also agree to meet the warranties and guarantees of performance outlined in Section 3.2(B) of the Firm PPA, including, but not limited to, the guaranteed equivalent availability factor ("EAF") of ninety percent (90%), the equivalent forced outage rate ("EFOR") of four percent (4%), and no more than three (3) disconnection events per contract year. Further, any minimum loads or minimum up-times driven by the technical and operational capabilities of the Facility should also be provided in the Proposal.

3.10.1.3 Proposals utilizing the ESPA are required to provide their BESS Contract Capacity (MW/MWh), which is the anticipated maximum net instantaneous active power and maximum energy storage capability (MWh stored that represents a 100% State of Charge) for export to the POI upon Commercial Operations. Proposals must also specify their Allowed Losses (kWh/24-hour period) which will be utilized for purposes of establishing the limit in Section 2.13 of the ESPA.

3.10.2 Paired Project and Standalone Storage Project Proposals are required to provide a single value Round Trip Efficiency ("RTE"), measured at the POI, that the Facility's BESS component is required to maintain throughout the term of the RDG PPA or ESPA. This

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[35] Since only the generation component of the Project generates energy, only its contributions should be counted in the NEP, which is intended to represent the potential net generation expected to be made available to the Company from the Project's siting and generating equipment and design. The benefit of the storage component will be included in the Company's production modeling of the Project dispatch.

[36] If a Proposal is selected to the Final Award Group and a RDG PPA is executed between the Company and the Proposer, the NEP RFP Projection will be further evaluated at several steps throughout the process as set forth in the RDG PPA, and adjustments to the Lump Sum Payment will be made accordingly. Additionally, because the Company will rely on an accurate representation of the NEP RFP Projection in the RFP evaluation, a one-time liquidated damage as described in the RDG PPA will be assessed if the First NEP Benchmark is less than the Proposer's NEP RFP Projection. After the Facility has achieved commercial operations, the performance of the Facility will be assessed on a continuing basis against key metrics identified in the RDG PPA. See Article 2 and Attachment U of the RDG PPA.

RTE value will be used in the RFP evaluation process and therefore Proposers will be held to this provided value as it will become the RTE Performance Metric in Section 2.11 of the RDG PPA or ESPA. Review the applicable Stage 3 Contract for potential liquidated damages assessed against Seller if the BESS does not maintain the required RTE. The RTE is further specified in Appendix B, Section 2.2.4.

3.10.3 Each Proposer must also agree to provide Project financial information, including proposed Project finance structure information as specified in Appendix B. Such information will be used to evaluate Threshold Requirements and non-price criteria (e.g., Financial Compliance, Financial Strength and Financing Plan, State of Project Development and Schedule) set forth in Sections 4.3 and 4.4.2. Upon selection, the Final Award Group may be requested to provide further detailed cost information if requested by the PUC or the Consumer Advocate as part of the Stage 3 Contract approval process. If requested, such information would be provided to the PUC, Consumer Advocate, and Company pursuant to a protective order in the docket.

3.10.4 The Proposer agrees that no material changes or additions to the Facility from what is submitted in its Proposal will be made without the Proposer first having obtained prior written consent from the Company. Evaluation of all Proposals in this RFP is based on the information submitted in each Proposal at the Proposal Due Date. If any Proposer requests any Proposal information to be changed after that date, the Company, in consultation with the Independent Observer, and in consideration of whether the evaluation is affected, will determine whether the change is permitted.

3.11 Potential Sites

3.11.1 Potential Sites Identified through the Land RFI

As an alternative to a Site identified by the Proposer, the Company has identified potential sites where landowners have expressed a willingness to negotiate a lease or purchase of the land to support a renewable energy project. These sites were identified through a Land Request for Information ("Land RFI") issued on June 15, 2020. Proposers will be responsible for working directly with the landowner and must secure Site Control with such landowner prior to submitting a Proposal. The information that has been gathered through this RFI is available upon request by following the instructions at http://hawaiianelectric.com/landrfi. Land RFI information is available to interested parties who sign the NDA.

This information is being provided for Proposers' consideration only. Project proposals submitted in response to this RFP are not required to be sited at a location identified through the Land RFI. The Hawaiian Electric Companies also make no representations as to the suitability of the listed sites for renewable energy production with regard to resource quality, interconnection constraints, zoning and permitting issues, community support, or other issues. Proposers should perform their own evaluation of these factors in determining whether a site is suitable for renewable energy project development. After further evaluation, Proposers that are interested in any of the identified sites are invited to engage in further discussions directly with landowners to negotiate any required rights to use the property. A Proposer may ask the Company questions as set forth in Section 2.2.1 if it seeks interconnection information at a specific proposed Site.

3.11.2 Hawai‘i Powered – Renewable Energy Zones Feedback

The Company has begun a process to identify areas with potential for future renewable energy development. While the whole of this work is not yet complete and available for this RFP, as part of this process the Company has started community outreach and invited members of the community to provide feedback on areas of the island that the Community is or is not amenable to use for renewable energy projects and to provide other feedback that would be helpful in siting renewable energy projects. This information is available at www.hawaiipowered.com/rez. While intended to be used as part of the development of Renewable Energy Zones for future RFPs beyond this Stage 3 RFP, such community feedback may be instructive for Proposers in this RFP. Proposers are encouraged to carefully review such information when selecting sites and developing their community outreach plans. In addition, the Hawaii State Energy Office has developed a community engagement strategy called Energize Kākou[37] which includes a guide for best practices for community engagement.

3.12 Confidentiality

3.12.1 Each prospective Proposer must submit an executed NDA in the form attached as Appendix E by the respective Proposal Due Date specified in the RFP Schedule in Section 3.1, Table 2. The form of the NDA is not negotiable. Information designated as confidential by the Company will be provided on a limited basis, and only those prospective Proposers who have submitted an executed NDA will be considered. NDAs that were fully executed for prior non-Stage 3 RFPs will not be accepted. Proposers must clearly identify all confidential information in their Proposals. However, Proposers should designate as confidential only those portions of their Proposals that genuinely warrant confidential treatment. The Company discourages the practice of marking every page of a Proposal as confidential. The Company will make reasonable efforts to protect any such information that is clearly marked as confidential. Consistent with the terms of the NDA, the Company reserves the right to share any information, even if marked confidential, to its agents, contractors, or the Independent Observer for the purpose of evaluating the Proposal and facilitating potential contract negotiations.

3.12.2 Proposers, in submitting any Proposal(s) to Company in response to this RFP, certify that such Proposer has not shared its Proposal(s), or any part thereof, with any other Proposer of a Proposal(s) responsive to this RFP. The Proposer shall acknowledge this in the Response Package submitted with its Proposal. Notwithstanding such certification, if the Company observes or receives evidence from a Proposer that appears to place one or more Proposers in violation of this RFP Section 3.12.2, e.g., a representative from one Proposer uses the same information in multiple Proposals submitted by different Proposers (e.g. individual Proposers with different names, joint ventures, etc.), Company

[37] Energize Kākou website is available at https://energy.hawaii.gov/get-engaged/energize-kakou/. The Playbook of community engagement best practices is available at https://energy.hawaii.gov/wp-content/uploads/2022/10/Energize-Kakou-Playbook_FINAL.pdf.

will seek additional information and clarification from such Proposer(s) to determine whether such a violation does in fact exist (and, if so, in consultation with the Independent Observer, whether disqualification of one or more Proposals is appropriate).

3.12.3 The Company will request that the PUC issue a protective order to protect confidential information provided by Proposers to the Company and to be filed in a proceeding before the PUC. A copy of the protective order, once issued by the PUC, will be provided to Proposers. Proposers should be aware that the Company may be required to share certain confidential information contained in Proposals with the PUC, the State of Hawaiʻi Department of Commerce and Consumer Affairs, Division of Consumer Advocacy, and the parties to any docket instituted by the PUC, provided that recipients of confidential information have first agreed in writing to abide by the terms of the protective order. Notwithstanding the foregoing, no Proposer will be provided with Proposals from any other Proposer, nor will Proposers be provided with any other information contained in such Proposals or provided by or with respect to any other Proposer.

3.13 Credit Requirements

3.13.1 Proposers with whom the Company enters into an RDG PPA, Firm PPA or ESPA must post Development Period Security and Operating Period Security in the form of an irrevocable standby letter of credit from a bank doing business in the United States and subject to United States state or federal regulation, with a credit rating of "A-" or better from Standard & Poor's ("S&P") or A3 or better from Moody's as required and set forth in Article 14 of the RDG PPA or ESPA, or Article 7 of the Firm PPA. Cash, a parent guaranty, or other forms of security will not be accepted in lieu of the irrevocable standby letter of credit.

3.13.2 The Development Period Security and Operating Period Security identified in the RDG PPA, Firm PPA or the ESPA are minimum requirements. Proposers shall not propose an amount lower than that set forth in the RDG PPA, Firm PPA or the ESPA.

3.13.3 Each Proposer shall be required to provide a satisfactory irrevocable standby letter of credit in favor of the Company from a bank doing business in the United States and subject to United States state or federal regulation, with a credit rating of "A-" or better from S&P or A3 or better from Moody's to guarantee Proposer's payment of interconnection costs for all Company-Owned Interconnection Facilities in excess of the Total Estimated Interconnection Costs and/or all relocations costs in excess of Total Estimated Relocation Costs that are payable to Company as required and set forth in Attachment G to the RDG PPA, Firm PPA or the ESPA.

3.13.4 Proposers may be required to provide an irrevocable standby letter of credit in favor of the Company from a bank doing business in the United States and subject to United States state or federal regulation, with a credit rating of "A-" or better from S&P or A3 or better from Moody's in lieu of the required Source Code Escrow in an amount and as required and set forth in Attachment B to the RDG PPA or the ESPA. Source code escrow is not required for synchronous generators.

3.13.5

Chapter 4: Evaluation Process and Evaluation Criteria

4.1 Proposal Evaluation and Selection Process

The Company will employ a multi-step evaluation process. Once the Proposals are received, the Proposals will be subject to a consistent and defined review, evaluation, and selection process. This Chapter provides a description of each step of the process, along with the requirements of Proposers at each step. Figure 1 sets forth the flowchart for the proposal evaluation and selection process.

Upon receipt of the Proposals, the Company will review each Proposal submission to determine if it meets the Eligibility Requirements and the Threshold Requirements. The Company, in coordination with the Independent Observer will determine if a Proposer is allowed to cure any aspect of its Proposal or whether the Proposal would be eliminated based on failure to meet either Eligibility or Threshold Requirements.[38] If a Proposer is provided the opportunity to cure any aspect of its Proposal, the Proposer shall be given three (3) business days to cure from the date of notification to cure.[39] Proposals that have successfully met the Eligibility and Threshold Requirements will then enter a two-phase process for Proposal evaluation, which includes the Initial Evaluation resulting in the development of a Priority List, followed by the opportunity for Priority List Proposals to provide Best and Final Offers, and then a Detailed Evaluation process to arrive at a Final Award Group.

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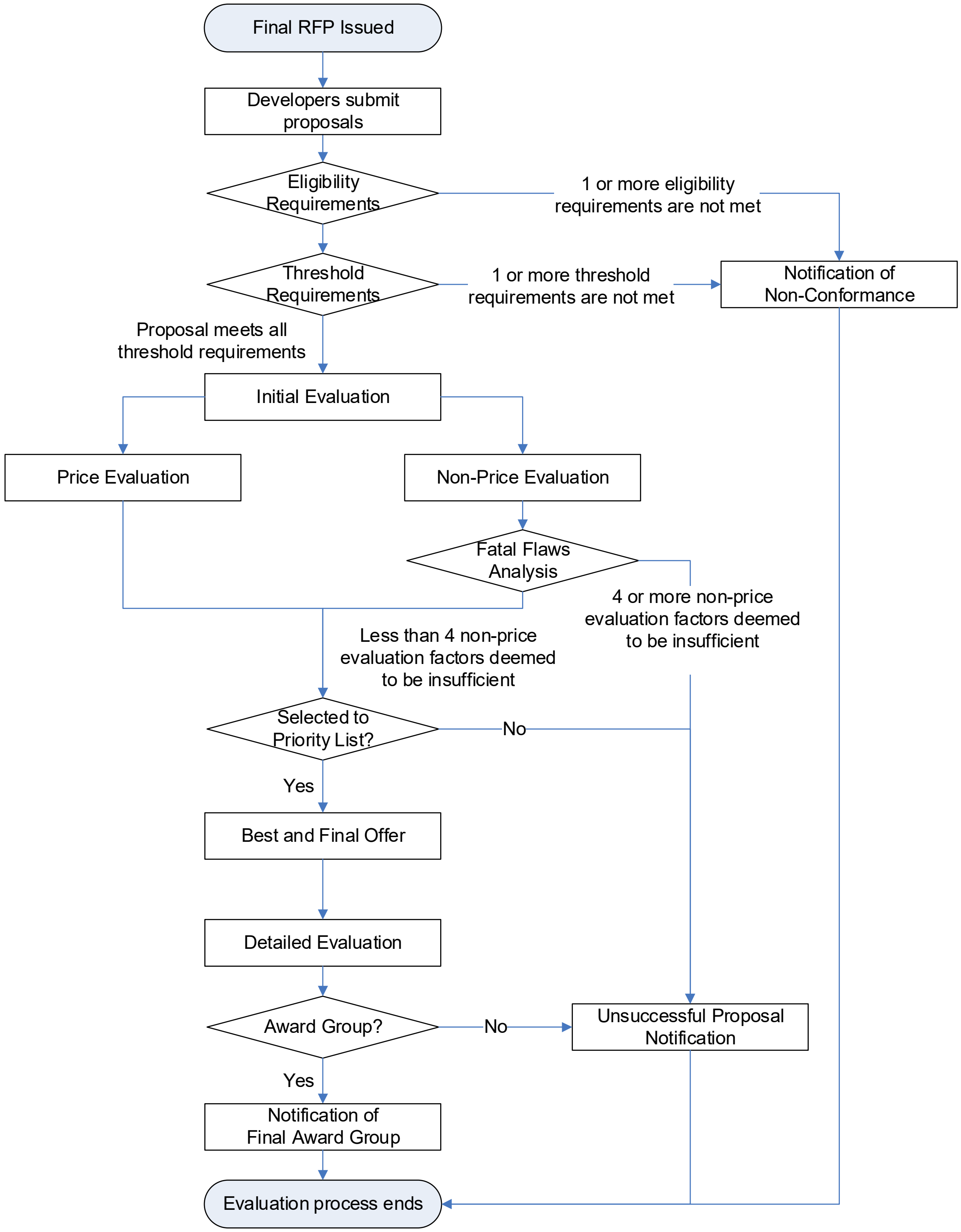
[38] As a general rule, if a Proposer does not include a requested document, inadvertently excludes minor information or provides inconsistencies in its information, it may be given a chance to cure such deficiency. If a Proposer fails to provide material required information in its Proposal and providing the Proposer an opportunity to cure is deemed by the Company, in consultation with the Independent Observer, as an unfair advantage to such Proposer, the Proposal could be classified as non-conforming and eliminated for failure to meet the Eligibility Requirements.

[39] The three (3) business day period will apply to the initial opportunity to cure. The Company, at its discretion, and in consultation with the Independent Observer, may allow for additional cure periods, if any, for subsequent inquiries.

Figure 1 – Evaluation Workflow



4.2 Eligibility Requirements Assessment

Upon receipt of the Proposals, each Proposal will be reviewed to ensure that it meets the following Eligibility Requirements.

1. The Proposal including required uploaded files must be received on time via the Electronic Procurement Platform.
2. The Proposal Fee must be received on or before the Proposal Due Date.[40]
3. The Proposal must not contain material omissions.
4. The Proposal must be signed and certified by an officer or other authorized person of the Proposer.
5. The Proposer must fully execute the NDA and any other document required pursuant to this RFP.
6. The Proposer must provide a Certificate of Vendor Compliance from the Hawaiʻi Compliance Express with their Proposal that is current (dated and issued no earlier than 60 days of the date of Proposal submission). A Certificate of Good Standing from the State of Hawaiʻi Department of Commerce and Consumer Affairs and also a federal and Hawaiʻi state tax clearance certificates for the Proposer may be substituted for the Certificate of Vendor Compliance.
7. The Proposal must not be contingent upon changes to existing county, state, or federal laws or regulations.
8. The proposed Project must be located on Oʻahu and interconnect to the Hawaiian Electric System as identified in Section 2.2.1.
9. The proposed Project must be greater than 5 MW.
10. The proposed Project must interconnect at the 138 or 46 kV level or existing Company substation offered in this RFP.
11. No single point of failure from the Facility shall result in a decrease of active power output measured at the Project's POI greater than 142 MW.
12. The proposed Project infrastructure and POI must be located outside the 3.2 feet sea level rise exposure area (SLR-XA) as described in the Hawaiʻi Sea Level Rise Vulnerability and Adaptation Report (2017), not located within a Tsunami Evacuation Zone, and not located within the Hawaii Department of Land and Natural Resources flood map's flood zones A, AE, AEF, AH, AO, VE.
13. Proposals for Variable Generation Projects, Paired Projects and Standalone Storage Projects must specify a GCOD that has been carefully considered and that is no later than December 1, 2027. Firm renewable dispatchable generation Project Proposals must specify a GCOD that has been carefully considered and that is no later than December 1, 2029 (for Tranche 1) and no later than December 1, 2033 (for Tranche 2).
14. Proposers must confirm the available MW capacity at the POI and/or available substation accommodation with the Company for the interconnection of their proposed Project.
15. Proposers shall agree to post Development Period Security and Operating Period Security as described in Section 3.13.

[40] Proposal Fees will not be required for Hawaiian Electric Proposals.

4.3 Threshold Requirement Assessment

Proposals that meet all the Eligibility Requirements will then be evaluated to determine compliance with the Threshold Requirements, which have been designed to screen out Proposals that are insufficiently developed, lack demonstrated technology, or will impose unacceptable execution risk for the Company.

Proposals must provide explanations and contain supporting information demonstrating how and why the Project proposed meets each of the Threshold Requirements. Proposals that fail to provide this information or meet a Threshold Requirement will be eliminated from further consideration upon concurrence with the Independent Observer.

The Threshold Requirements for this RFP are the following:

1. **Site Control:** The Proposal must demonstrate that the Proposer has Site Control for all real property required for the successful implementation of a specific Proposal at a Site not controlled by the Company, including any Interconnection Facilities, with the exception of right-of-way or easements for the interconnection route, for which the Proposer is responsible. The need for a firm commitment is necessary to ensure that Proposals are indeed realistic and can be relied upon as the Company moves through the remainder of the RFP process.

   Site Control will be judged by how well the documentation demonstrates the Proposal meeting this Site Control requirement. Proposers must do one of the following:

   - Provide documentation confirming (1) that the Proposer has an existing legally enforceable right to use and control the Site, either in fee simple or under leasehold for a term at least equal to the term of the Stage 3 Contract ("Site Control") as specified in the Proposer's Proposal (taking into account the timelines set forth in this RFP for selection, negotiation, and execution of a Stage 3 Contract and PUC approval as applicable), and (2) the applicable zoning for the Site and that such zoning does not prohibit the development of the Site consistent with the Proposal; or
   - Provide documentation confirming, at a minimum, (1) that the Proposer has an executed binding letter of intent, memorandum of understanding, option agreement, or similar document with the landowner (a "binding commitment") which sets forth the general terms of a transaction that would grant the Proposer the required Site Control, and (2) the applicable zoning for the Site and that such zoning does not prohibit the development of the Site consistent with the Proposal. The binding commitment does not need to be exclusive to the Proposer at the time the Proposal is submitted and may be contingent upon selection of the Proposal to the Final Award Group. If multiple Projects are provided a binding commitment for the same Site, the documents granting the binding commitments must not prevent the Company from choosing the Proposal that otherwise would have been selected.

- Government/Public Lands Only: The above two bullet points may not be feasible where government or publicly-owned lands are part of the Site or are required for the successful implementation of the Proposal. In such a case, at a minimum the Proposer must provide a credible and viable plan, including evidence of any steps taken to date, to secure all necessary Site Control for the Proposal, including but not limited to evidence of sufficient progress toward approval by the government agency or other body vested with the authority to grant such approval (as demonstrated by records of the agency). The Proposer will still be required, however, to demonstrate Site Control as required in the Stage 3 Contract should the Proposal be selected to the Final Award Group.

While land rights for the interconnection route are not required at the time of submission of the Proposal, (1) the Proposal must thoroughly describe the interconnection route as set forth in Attachment B, Section 2.5.4, and (2) if the Proposal is selected to the Final Award Group, and if the Proposer and Company are able to reach agreement on a Stage 3 Contract, it will be the Proposer's sole responsibility to obtain all required land rights within the timeframes set forth in the Stage 3 Contract. The Proposer must also provide a credible and viable plan for obtaining such rights-of-way or easement(s), including the proposed timeline, the identification of all steps necessary to obtain such right-of-way or easement(s), and evidence of any steps taken to date. In addition, developmental requirements and restrictions such as zoning of the Site and the status of easements must be identified and will be considered in determining whether the Proposal meets the Site Control threshold.

2. **Performance Standards:** The proposed Facility must be able to meet the performance attributes identified in this RFP and the Performance Standards identified in Section 2.1 of this RFP. Proposals shall include sufficient documentation to support the stated claim that the Facility will be able to meet the Performance Standards. The Proposal shall include information required to make such a determination in an organized manner to ensure this evaluation can be completed within the evaluation review period.

3. **Proven Technology:** This criterion is intended as a check to ensure that the technology proposed is viable and can reasonably be relied upon to meet the objectives of this RFP. The Company will only consider Proposals utilizing technologies that have successfully reached commercial operations in commercial applications (i.e., a power purchase agreement) at the scale being proposed. Proposals should include any supporting information for the Company to assess the commercial and financial maturity of the technology being proposed.

4. **Experience of the Proposer:** The Proposer, its affiliated companies, partners, and/or contractors and consultants on the Proposer's Project team must have experience in financing, designing, constructing, interconnecting, owning, operating, and maintaining at least one (1) electricity generation and/or standalone storage project, including all components of the project (i.e., paired energy storage

or other attributes), similar in size, scope, technology, and structure to the Project being proposed by Proposer. The Company will consider a Proposer to have reasonably met this Threshold Requirement if the Proposer can provide sufficient information in its Proposal's RFP Appendix B Section 2.13 tables demonstrating that at least one member of the Proposer's team (identified in the Proposal) has specific experience in each of the following categories: financing, designing, constructing, interconnecting, owning, operating, and maintaining projects similar in size and scope to the Project being proposed.

5. **Financial Compliance:** The proposed Project must not cause the Company to be subject to consolidation, as set forth in Financial Accounting Standards Board ("FASB") Accounting Standards Codification Topic 810, Consolidation ("ASC 810"), as issued and amended from time to time by FASB. Proposers are required to state to the best of their knowledge, with supporting information to allow the Company to verify such conclusion, that the Proposal will not result in the Seller under the Stage 3 Contract being a Variable Interest Entity and result in the Company being the primary beneficiary of the Seller that would trigger consolidation of the Seller's finances on to the Company's financial statements under FASB ASC 810. The Company will perform a preliminary consolidation assessment based on the Proposals received. The Company reserves the right to allow a Proposal to proceed through the evaluation process through selection of the Priority List and work with the Proposer on this issue prior to or during contract negotiations.

6. **Community Outreach:** Gaining community support is an important part of a Project's viability and success. A comprehensive community outreach and communications plan ("Community Outreach Plan") is an essential roadmap that guides a developer as they work with various communities and stakeholders to gain their support for a Project. Proposers must include a Community Outreach Plan that describes the Proposer's commitment to work with the neighboring community and stakeholders and to provide them timely Project information during all phases of the Project. The Community Outreach Plan shall include, but not be limited to, the following information: Project description, community scoping (including stakeholders and community concerns), Project benefits, government approvals, development process (including Project schedule), plan for reporting construction schedules and activities which include resulting impacts (e.g., traffic, noise, and dust) and mitigation plans beginning at least one month prior to the start of scheduled work, and a comprehensive communications plan which factors in monthly Project status updates and includes a timeline. Hawaiian Electric will carefully review the Community Outreach Plans to ensure that outreach to residents, area elected officials and known community leaders and organizations is documented and that the plan is tailored by community and includes the outreach schedule, communication plans and required project information that will be shared in each engagement.

7. **Cultural Resource Impacts:** Proposers need to be mindful of the Project's potential impacts to historical and cultural resources. Proposers must identify: (1) valued cultural, historical, or natural resources in the area in question, including the extent to which traditional and customary native Hawaiian rights are exercised in the area; (2) the extent to which those resources – including traditional and customary native Hawaiian rights – will be affected or impaired by the proposed action; and (3) the feasible action, if any, to be taken to reasonably protect any identified cultural, historical, or natural resources in the area in question, and the reasonable protection of traditional and customary native Hawaiian rights in the affected area. Proposers must also have already contracted with a consultant with expertise in this field to begin a cultural assessment for the Project.

   Also, at a minimum, Proposers must conduct and provide at least an initial Archaeological Literature Review of existing cultural documentation filed with the State Historic Preservation Division and a Field Inspection Report which identifies any known archaeological and/or historical sites within the project area. If sites are found, Proposers must provide a plan for mitigation from an archaeologist licensed in the State of Hawaii. An Archaeological Literature Review and Field Inspection Report should ideally be submitted at the appropriate Proposal Due Date in Table 2. However, if it is not submitted with the Proposal, these must be submitted three weeks before the Selection of Priority List date in Section 3.1, Table 2. If Proposers are unable to deliver the required cultural documentation with the allocated timeframe due to access and right of entry issues, the Company will work with Proposers to deliver a documented Field Inspection Report prior to signing of the Stage 3 Contract.

8. **Available MW Capacity:** This criterion is intended as a check to ensure that the proposed Project's Net Nameplate Capacity is within the available MW capacity of the 138 kV or 46 kV transmission-level line or substation identified for interconnection.[41]

9. **Technical Model:** Developing an accurate and functional facility technical model is imperative to commencing the Interconnection Requirement Study phase of the process. This criterion is to check whether Proposers have provided the required models per Appendix B, Attachment 4, as well as documentation that Proposers have tested their models under all scenarios prescribed in Appendix B, Attachment 3.[42]

10. **State of Project Development and Schedule & Permitting:** Projects must fully demonstrate how they will reach their GCOD specified, including identification of risks and schedule assumptions. Proposals must also fully demonstrate, via a

[41] The available MW capacity is verified under the assumption there is only one project interconnecting to the line. Interactions among proposed projects in close proximity with each other will be analyzed when the Company performs load flow analyses as described in Section 4.7 below.
[42] Proposers of an existing Project should contact the Company via the communication method identified in Section 1.6 to clarify any concerns they have about meeting all the model requirements in this RFP.

detailed critical path schedule, that the Project will be able to reach commercial operations as specified. This is particularly important for renewable firm capacity projects, as the need-by date in the RFP is critical to meet. Proposals shall include a Gantt chart that clearly illustrates the overall schedule and commercial operations by their specified GCOD. The Gantt chart shall include realistic task durations, accurate dependencies, tasks that will be fast tracked, as well as slack time and contingencies. The Gantt chart must also include the milestones identified in Appendix H, Section 4 and reflect the appropriate durations associated with such milestones. Proposals must be sure to include permitting and scheduling issues for any system upgrades.

Proposals shall identify all permits necessary for the Project and provide realistic durations to obtain such permits. Proposals shall also provide the current status of the permits (ex. permit application identified, permit application submitted, permit received).

4.4 Initial Evaluation – Price and Non-Price Analysis

Proposals that meet both the Eligibility and Threshold Requirements are Eligible Proposals which will then be subject to a price and non-price assessment. The Company will establish two teams to undertake the Proposal evaluation process: a Price Evaluation Team and Non-Price Evaluation Team. The results of the price and non-price analysis will be a relative ranking and scoring of all Eligible Proposals. Price-related criteria will account for sixty percent (60%) of the total score and non-price-related criteria will account for forty percent (40%) of the total score. The non-price criteria and methodology for applying the criteria are explained in Section 4.4.2.

The Company will employ a closed-bidding process for this solicitation in accordance with Part IV.H.3 of the Framework where the price and non-price evaluation models to be used will not be provided to Proposers. However, the Company will provide the Independent Observer with all necessary information to allow the Independent Observer to understand the evaluation models and to enable the Independent Observer to observe the entire analysis to ensure a fair process.

4.4.1 Initial Evaluation of the Price Related Criteria

For the initial price analysis, the Company will complete a levelized price calculation for each Project based on the contracted energy output (e.g., NEP) and/or capacity (e.g., MW, Contract Firm Capacity) using the fixed and variable pricing (as applicable per Stage 3 Contract type).

In order to fairly evaluate Proposals with different technologies and characteristics, the Company will group Proposals into technology-based and storage-based evaluation categories,[43] dependent on the types and quantities of Proposals received in this RFP. For example[44]: (1) Wind generation (MWh) only; (2) Wind generation (MWh) and Energy storage; (3) Solar generation (MWh) only; (4) Solar generation (MWh) and Energy storage; (5) Standalone Energy Storage (MW/MWh); (6) Firm synchronous generation (MW).

The Eligible Proposal with the lowest LEP in each evaluation category will receive 600 points. All other Eligible Proposals in that evaluation category will receive points based on a proportionate reduction using the percentage by which the Eligible Proposal's LEP exceeds the lowest LEP in that evaluation category. For example, if a Proposal's LEP is ten percent (10%) higher than the lowest LEP in that evaluation category, the Proposal will be awarded 540 points (that is, 600 points less 10%). The result of this assessment will be a ranking and scoring of each Proposal within each evaluation category.

In instances where Proposers offer a Proposal variation for the same resource type in the same electrical location (i.e., POI), only the highest scoring variation for that location and technology type will be considered for the Priority List.

4.4.2 Initial Evaluation of the Non-Price Related Criteria and Previous Performance

For the non-price analysis, each Proposal will be evaluated on each of the eleven (11) non-price criteria categories set forth in Section 4.4.2.1 below. The non-price score accumulated after evaluation of such criteria is subject to reduction based on a new Previous Performance evaluation described in Section 4.4.2.2 below.

4.4.2.1 Non-Price Criteria and Scoring

The non-price criteria are as follows and further described below:

1. Community Outreach
2. State of Project Development and Schedule
3. Performance Standards
4. Environmental Compliance and Permitting Plan
5. Experience and Qualifications
6. Financial Strength and Financing Plan
7. Proposed Contract Modifications
8. Carbon Emissions
9. Cultural Resource Impacts
10. Technical Model
11. Land Use and Impervious Cover

[43] If Proposals with various storage sizes are received in the RFP, different categories based on storage size will be established during the Initial Evaluation to enable the benefits of the Projects' storage to be assessed.

[44] There may be other technologies that are offered in this RFP. This list is illustrative of how technology-based evaluation categories will be established for the Initial Evaluation. The categorizing of Proposals will depend on the types and quantities of Proposals received in this RFP.

Each of the first three criteria – Community Outreach, State of Project Development and Schedule, Performance Standards – will be weighted twice as heavily as the others to reflect the impact these categories have on projects achieving a successful completion. The non-price criteria are generally scored on a scale of 1 (poor) to 5 (highly preferable). A score of 3 means that a Proposal meets the minimum standard for that criterion.

The Company's evaluation of the non-price criteria will be based on the materials provided by a Proposer in its Proposal. Acceptance of any Proposal into the Final Award Group shall not be assumed or construed to be an endorsement or approval that the materials provided by Proposer are complete, accurate or in compliance with applicable law. The Company assumes no obligation to correct, confirm, or further research any of the materials submitted by Proposers. Proposers retain sole responsibility to ensure their Proposals are accurate and in compliance with all laws.

The non-price criteria are:

1. **Community Outreach** – Gaining community support is an important part of a Project's viability and success. An effective Community Outreach Plan will call for early meaningful communications with stakeholders – that include area residents, elected officials and community leaders – and will reflect a deep understanding and respect for the community's desire for information and provide opportunities that enable them to make informed decisions about future projects in their communities. Therefore, Proposals will be evaluated on the quality of the Community Outreach Plan to inform the Project's impacted communities.

   Proposals should include a Community Outreach Plan that describes the Proposer's commitment to work with the neighboring community and stakeholders and to provide timely Project information during Project development, construction and operation. The more robust and customized the stakeholder list, meeting frequency, and commitments are defined in the plan, the higher the rating the Proposer will receive as part of the scoring and evaluation process. The Community Outreach Plan shall include, but not be limited to the following:
   1) Project description. A thorough description including a map of the location of the Project. This information will help the community understand the impact that the Project may have on the community.
   2) Community scoping. Identify stakeholders (individuals, community leaders, organizations), community issues and concerns, and community sentiment.
   3) Project benefits. An explanation of the need for the Project. This will help the community to understand how the Project might benefit their community.
   4) Government approvals. Required government permits and approvals, public hearings and other opportunities for public comment. This information will help the community to understand the level of public scrutiny and participation that might occur for the Project and the opportunities to provide public comments.

5) Development process. A Project schedule that identifies key Project milestones will facilitate the community's understanding of the development process.
6) Community benefits package. Details on the amount of funds that the Proposer will commit on an annual basis to providing as community benefits and other community benefits in addition to funding that the proposer intends to provide. At a minimum, Proposers should commit to setting aside at least $3,000 per MW per year for community benefits. These shall be donated to actions and/or programs aimed at addressing specific needs identified by the Host Community, or to a 501(c)(3) not-for-profit community-based organization(s) to directly address Host Community-identified needs. A documented community benefits package highlighting the distribution of funds must be developed by Proposers for the Company's review. This document will be made public on each Proposer's website and must demonstrate how funds will directly address needs in the Host Community to benefit community members. Proposers will provide details regarding the intended beneficiaries of the funds, including recipients, and the area(s) in which the funds will be directed. The community benefits package must include documentation of each Proposer's community consultation and input collection process to define Host Community needs, along with actions and programs aimed at addressing those needs. Preference will be given to Proposers that commit to setting aside a larger amount or commit to providing other benefits (including but not limited to creating local jobs, payment of prevailing wages, or improving community infrastructure). The Proposer may choose to identify and select an eligible non-profit organization to serve as the administrator for the duration of the contract term responsible for ensuring the project's community benefit is appropriately disbursed. Should a Proposer need an example of the use of a community benefit funding host, the Company will provide such example(s) upon request.
7) Communications Plan. A communications plan including a detailed community outreach schedule that will keep the affected communities and stakeholders informed about the Project's outreach efforts during early Project development period through construction and operations, including monthly Project status updates.

Preference will be given to Proposers who have already identified established contacts to work with the local community, have used community input to incorporate changes to the final design of the Project and mitigate community concerns, have proposed a community benefits package (including details of the community recipients and benefits package), or have community consultants as part of the Project team doing business in Hawaiʻi that have successfully worked with communities in Hawaiʻi on the development of two or more energy projects or projects with similar community issues. These criteria are aligned with the Company's community engagement expectation whereby all developers will be required to engage in community outreach prior to signing a Stage 3 Contract with the Company. This process is also outlined in RFP Section 5.3. Further information and instructions regarding expectations for the Community Outreach Plan are included as Attachment 5 and 6 to Appendix B.

Preference would also be given to a Proposer's commitment that eighty percent (80%) of non-supervisory construction and operations workers' hours associated with project construction or repowering of a project will be paid at prevailing wage equivalent indicated under HRS Chapter 104 during all periods of construction; and the preference to hire qualified construction and operations/maintenance workers from Hawai'i County, and the State of Hawai'i, in that order, before hiring non-resident laborers.

2. **State of Project Development and Schedule** – Projects that are further along in development generally have lower project execution risk and a greater probability of being able to be successfully placed into service prior to the GCOD (specifically identified in each Proposal). At a minimum, Projects should demonstrate how they plan to reach their GCOD specified, including identification of risks and schedule assumptions, and capture any tax-related safe harbors, if applicable. (Schedules must be created in Microsoft Project and submitted in .mpp file format and must identify the IRS completion date and PUC approval dates assumed.) Proposals must also fully demonstrate, via a detailed critical path schedule, that the Project will be able to reach commercial operations as specified. This is particularly important for renewable firm capacity projects, as the need-by date in the RFP is critical to meet. Proposals shall include a Gantt chart that clearly illustrates the overall schedule and demonstrates achievement of any tax-related safe harbor, if applicable, and commercial operations by their specified GCOD. The Gantt chart shall include task durations and dependencies, identify tasks that will be fast tracked, and identifies slack time and contingencies. This criterion will also look at the high-level Project costs set forth in the Proposal including: costs for equipment, construction, engineering, Seller-Owned Interconnection Facilities, Company-Owned Interconnection Facilities, land, annual O&M, the reasonableness of such costs and the assumptions used for such costs. The Company will specifically look to see if the Proposer has included all of the cost line items from Appendix H applicable to the Project type for Company-Owned Interconnection Facilities. An example of what the Company is looking for is identified in Appendix H, Attachment 1. Proposals that do not appear to include all the applicable cost line items from Appendix H that are reasonable for a project of the size proposed may result in a lower ranking for this criterion as it may reflect risk that the Project cannot be built on time and for the price proposed by the Proposer. The Company reserves the right to discuss any cost and financial information with a Proposer to ensure the information provided is accurate and correct. The Company may require an attestation from the Proposer that they understand their proposed interconnection costs do not appear accurate to the Company and should the Proposer continue and is selected that the Proposer shall be responsible for the final determination of interconnection costs whether or not it is higher than what the Proposer has included in its Proposal.

3. **Performance Standards –** The proposed Facility must be able to meet the performance attributes identified in this RFP (Section 2.1) and the Performance Standards identified in the applicable Stage 3 Contract. The Company will review the Proposal information received, including design documents and operating procedures materials provided in the Proposal, and evaluate whether the Project as designed is able to meet the Performance Standards identified in the applicable Stage 3 Contract and in this RFP. At a minimum, in addition to meeting the Performance Standards, the Proposal should include sufficient documentation, provided in an organized manner, to support the stated claim that the Facility will be able to meet the Performance Standards. The Proposal should include information required to make such a determination in an organized manner to ensure this evaluation can be completed on a timely basis. Preference will be given to Proposals that provide detailed technical and design information showing how each standard can be met by the proposed Facility. Preference will also be provided on facilities that offer additional capabilities over and above the required performance attributes.

4. **Environmental Compliance and Permitting Plan** – This criterion relates to the potential (short- and long-term) environmental impacts associated with each Project, the quality of the plan offered by the Proposer to mitigate and manage any environmental impacts (including any pre-existing environmental conditions), and the plan of Proposers to remain in environmental compliance over the term of the contract. These impacts are reflected on a technology-specific basis. Completing any necessary environmental review and obtaining required permitting in a timely manner is also important and Proposals will be evaluated on their plan to identify, apply for, and secure required permits for the Project, any permitting activity that has been completed to date, including having initial discussions with the applicable regulating agencies such as U.S. Fish and Wildlife and the State of Hawaiʻi Department of Land and Natural Resources' Division of Forestry and Wildlife, prior to submitting a Proposal, and the degree of certainty offered by the Proposer in securing necessary permits.

   At a minimum, proposed Projects should be expected to have minimal environmental impact for most areas and Proposals should provide a comprehensive plan to mitigate the identified potential or actual significant environmental impacts to remain in environmental compliance. The proposed mitigation plans should be included in the Project timeline. Preference will be given to Proposals that provide a more detailed plan as well as those that have proactively taken steps to mitigate potential environmental impacts.

   Also, this criterion requires that, at a minimum, Proposers should have identified, and disclosed in their Proposal(s) all major permits, approvals, appurtenances and entitlements (including applicable access, rights of way and/or easements) (collectively, the "permits") required and have a preliminary plan for securing such permits. Preference will be given to Proposals that are able to provide a greater degree of certainty that its plan to secure required permits is realistic and achievable, or have already received all or a majority of the required permits. The Proposer should disclose all identified (a) discretionary permits required, i.e., those requiring public or contested case hearings and/or review and discretionary approval by an appropriate government agency and (b) ministerial conditions without discretionary approval conditions. In all cases, the Proposer must provide a credible and viable plan to secure all necessary and appropriate permits necessary for the Project. For example, if the Project is located within an agricultural district, the Proposer shall provide evidence of Proposer's verification with the appropriate government agency that the Project complies with HRS Section 205-2 and Section 205-4.5, relating to solar energy facilities placed on agricultural land, provided, however that where a special use permit (under Section 205-6), exemption (under Section 205-6), or amendment to land use district boundary lines (under Section 205-4) is required to secure such compliance, Proposer shall identify the need for such permit, exemption or amendment and provide a list of required prerequisites and/or conditions and a realistic timeline necessary to obtain such permit, exemption or amendment satisfactory for Proposer to still meet its designated GCOD.

The Proposal's non-price score for this requirement will reflect the lower of either the Environmental Compliance sub-score or the Permitting Plan sub-score.[45]

5. **Experience and Qualifications** – Proposals will be evaluated based on the experience of the Proposer in financing, designing, constructing, interconnecting, owning, operating, and maintaining projects (including all components of the project) of similar size, scope and technology. At a minimum, Proposals must show via the table format specified in RFP Appendix B, Section 2.13 that at least one (1) member must have specific experience in each of the following categories: financing, designing, constructing, interconnecting, owning, operating, and maintaining at least one electricity generation project including all components of the project similar to the Project being proposed. Preference will be given to Proposers with experience in successfully developing multiple projects that are similar to the one being proposed and/or that have prior experience successfully developing and interconnecting a utility-scale project to the Company's System.

6. **Financial Strength and Financing Plan** – This criterion addresses the comprehensiveness and reasonableness of the financial plan for the Project as well as assesses the financial strength and capability of the Proposer to develop the Project. A complete financial plan addresses the following issues: Project ownership, capital cost and capital structure, sources of debt and equity, and evidence that credit-worthy entities are interested in financing the Project. The financial strength of Proposers or their credit support providers will be

[45] Two different teams will assess the Proposals for this non-price criteria – one focusing on the environmental impacts of the Proposal and the other on the permitting plans and activities of the Proposer. Each team will contribute a sub-score, and the overall score for this criterion will be based on the lower of the two sub-scores.

considered, including their credit ratings. The financing participants are expected to be reasonably strong financially. Developers and their sources of capital that have investment grade credit ratings from a reputable credit rating agency (S&P, Moody's, Fitch) will also be given preference, with those that have higher credit ratings ranked higher.

7. **Proposed Contract Modifications** – Proposers are encouraged to accept the contract terms identified in the applicable model Stage 3 Contract in their entirety to expedite the overall RFP process and potential contract negotiations. Proposers who accept the Stage 3 Contract without edits will receive a higher score and will be the only Proposals that can achieve the highest scoring for this non-price evaluation criterion. Technology-specific or operating characteristic-required modifications, with adequate explanation as to the necessity of such modifications, will not jeopardize a Project's ability to achieve the highest score. Proposers who elect to propose modifications[46] to the model agreements shall provide a Microsoft Word red-line version of the applicable document identifying specific proposed modifications to the model agreement language, as well as a detailed explanation and supporting rationale for each modification. General comments without proposed alternate language, drafting notes without explanation or alternate language, footnotes such as "parties to discuss," or a reservation of rights to make additional modifications to the model agreements at a later time are unacceptable, will be considered unresponsive, and will result in a lower score. See also Section 3.8. The Company and Independent Observer will evaluate the impact that the proposed modifications will have on the overall risk assessment associated with the evaluation of each Proposal.

8. **Carbon Emissions** – Proposals should provide responses to the Carbon Criteria Questions provided in Section 2.15 of Appendix B, which will be used to score each Project depending on Project-specific design, siting, procurement, construction and O&M information likely to impact the Project's lifecycle GHG emissions. In line with carbon neutral goals set forth by Hawaiian Electric[47] and the State of Hawai'i,[48] preference will be given to Proposers expected to have lower lifecycle GHG emissions based on the responses to the Carbon Criteria Questions.

9. **Cultural Resource Impacts** – Proposers need to be mindful of the Project's potential impacts to historical and cultural resources. Proposers should have identified (1) valued cultural, historical, or natural resources in the area in question, including the extent to which traditional and customary native Hawaiian rights are exercised in the area; (2) the extent to which those resources – including traditional and customary native Hawaiian rights – will be affected or impaired by the proposed action; and (3) the feasible action, if any, to be taken to reasonably protect any identified cultural, historical, or natural resources in the area in

[46] See Section 3.8.8 for all non-negotiable sections of the Stage 3 Contracts.
[47] See https://www.hawaiianelectric.com/about-us/our-vision-and-commitment/climate-change-action.
[48] See HRS § 225P-5.

question, and the reasonable protection of traditional and customary native Hawaiian rights in the affected area.

Also, Proposers should have already contracted with a consultant with expertise in this field to begin a cultural assessment for the Project. Proposals will be evaluated on the Proposer's plan and commitment to addressing cultural resource impacts on their Project, if any. Therefore, in order to be evaluated for this criterion, Proposers should, at least, provide the following documentation, as applicable: (1) Proposer's or its consultant's experience with cultural resource impacts on past projects; (2) the status of their cultural assessment plan. Should the Project Proposal cite a previously completed cultural assessment of the area, a copy of the assessment document should be included. Proposals will be evaluated on the extent to which their cultural assessment plan has been developed, and preference will be given to Proposals that are further along in the assessment process, including but not limited to, whether a mitigation/action plan has been provided that addresses any identified cultural resource issues, or a date for when such a plan will be available has been identified, or any portions of such plan have been completed.

10. **Technical Model** – Developing an accurate and functional facility technical model is imperative to the successful completion of the IRS, the accuracy of study results, and, by extension, the reliability of the System. Models must be accurate representations of the Facility and its operation. The Company validates the quality of the models and acceptability for the IRS though a model checkout process. Proposers should have developed, executed, tested, and documented results of their models prior to submitting a proposal. This criterion is to evaluate the extent to which Proposers have met the requirements in Appendix B, Attachment 3. Scoring will be based on the Proposer's documentation, which are the result of self-testing and benchmarking documentation, demonstrating the model's ability to meet the requirements of Appendix B, Attachment 3. Preference will be given to Proposals for which the accompanying documentation show they are able to meet the requirements and achieve the expected results for all scenarios proposed in Appendix B, Attachment 3.

11. **Land Use and Impervious Cover** – The Company encourages Proposers to site Projects on developed lands and to preserve open spaces and agricultural lands. Proposers will be scored more favorably for locating Projects on:
    - Land with greater existing impervious cover;[49]
    - Land zoned industrial or industrial mixed use, commercial or business mixed use, or apartment or apartment mixed use, based on county zoning designations, with a preference in that order; or

[49] As defined by the Environmental Protection Agency ("EPA") (8 Tools of Watershed Protection in Developing Areas | Watershed Academy Web | US EPA), impervious cover is "the sum total of all hard surfaces within a watershed including rooftops, parking lots, streets, sidewalks, driveways, and surfaces that are impermeable to infiltration of rainfall into underlying soils/groundwater." For purposes of evaluation, PV panels shall be considered impervious.

- Land deemed as reclaimed, such as brownfield.[50]

In addition, projects that minimize the net increase of impervious cover of a Project site will be scored more favorably.

4.4.2.2 Previous Performance Evaluation.

A new overall Previous Performance scoring criterion will be employed in this RFP. Based on any underperformance experienced within the past five (5) years from any Proposer, its parent company, or an affiliate of such Proposer, the Company will deduct points from the Proposer's total non-price score based on the infraction. Unlike the 11 non-price criteria above that generally score each project on a scale of 1 to 5, the Previous Performance scoring criteria will deduct points from the total non-price score. The total deductions could range from 0 to 20 points. If a Proposer has not been awarded a project by the Company or does not have an existing or past contract with the Company within the past five years, no points will be deducted.

The Company will evaluate Proposers (which for purposes of the Previous Performance criteria, includes the Proposer, its parent company, or any affiliate) for any past underperforming infractions listed below. For each of the following infractions identified for any of the Proposer's existing or past projects, points will be deducted, up to a maximum of ten (10) points, from the Proposer's total non-price score in this RFP. Any infraction caused by force majeure will not be counted into the deductions.

1. Proposer declined a Priority List or Final Award Group invitation. [1 point deduction]
2. Proposer withdrew from an awarded project after accepting a Final Award Group invitation. [2 point deduction]
3. Proposer terminated an executed contract, except for a termination due to a Company-event of default, including declaring the contract null and void, except for a null and void declaration due to an unfavorable PUC order, which was not reinstated or otherwise superseded by a subsequent contract. [2 point deduction]
4. Termination of an executed contract by Company due to a Proposer-, parent company-, or affiliate-event of default, unless such default was cured by the contracting Proposer, parent company, or affiliate in an expeditious manner to the satisfaction of the Company. [2 point deduction]
5. Proposer missed the Guaranteed Commercial Operations Date under an existing or past PPA. [1 point deduction for missing GCOD by more than 10 days up to 3 months, 2 point deduction for missing GCOD more than 3 months up to 6 months, and 3 point deduction for missing GCOD by more than 6 months.]
6. Proposer missed one or more PPA Milestones or Seller's Conditions Precedents, other than GCOD, by more than 10 days. [1 point deduction]

[50] As defined by the EPA (Overview of EPA's Brownfields Program | US EPA), brownfield is "a property, the expansion, redevelopment, or reuse of which may be complicated by the presence or potential presence of a hazardous substance, pollutant, or contaminant."

7. Proposer paid LDs during the development phase of the project. [0.5 point deduction]
8. Proposer breached its representations and warranties under the PPA. [0.5 point deduction]
9. Proposer failed to remedy one or more violations of the Company's performance standards during operations within 6 months. [0.5 point deduction]
10. During the operating term of the PPA, Proposer paid LDs or failed to meet one or more performance metrics, warranties or guarantees (NEP, EAF, EFOR, MPR, Unit Trips, etc.) for more than one reporting period. [0.5 point deduction]

In addition to the above-referenced infractions, ten (10) points shall be deducted from any Proposal's non-price score in the event the Proposer, its parent company, or an affiliate of the Proposer is involved in any pending litigation in which the Proposer, parent company, or affiliate has made claims against the Company or in which the Company has made claims against the Proposer, parent company, or affiliate, which is not subject of a settlement agreement that is currently in effect. This ten-point deduction for involvement in pending litigation is not subject to the maximum of ten (10) points that may be deducted for the other Previous Performance criteria delineated above. As such, a total of up to twenty (20) points may be deducted from a Proposal's non-price score for infractions of Previous Performance criteria.

During the non-price criteria evaluation, should the Company identify any Previous Performance infractions, including the identification of pending litigation, the Company will notify Proposers of any potential deductions and provide them with the opportunity to respond with a written explanation within 5 business days. The Company, in consultation with the Independent Observer, will review the explanations and determine whether there were instances outside of the Proposer's control or otherwise excusable. The Company will finalize deductions with the objective of determining the risk of future under/non-performance based on past experiences.

The resulting non-price score will be the sum of the scores for each of the individual non-price criteria minus any points deducted for underperformance infractions based on this new Previous Performance scoring criterion. The Company will then award non-price evaluation points in accordance with the relative ranking of scores within each evaluation category. The Proposal in each evaluation category with the highest total non-price score will receive 400 points, and all other Proposals will receive points equal to the Proposal's score divided by the top score, multiplied by 400.

During the non-price criteria evaluation, a fatal flaws analysis will also be conducted such that any Proposal that is deemed not to meet the minimum standards level for four (4) or more non-price criteria will be disqualified given that the Proposal has failed to meet the required number of non-price factors that are indicative as to the general feasibility and operational viability of a proposed Project.

4.5 Selection of a Priority List

At the conclusion of both the price and non-price analysis, a total score will be calculated for each Proposal using the 60% price-related criteria / 40% non-price-related criteria weighting outlined above. The price and non-price analysis, and the summation of both price and non-price scores described above, will result in a ranking of Proposals within each technology-based evaluation category.

Following the price and non-price scoring, an initial pool of top scoring Proposals for each technology-based category with consideration for electrical location of each resource will be determined. The Company may consider using a computer model to optimize the pool of resources by technology category in order to select Proposals in each technology-based category to advance to the Priority List.

The collective export of portfolios will be reviewed against the existing transmission available MW capacity.

The selection to the Priority List does not assure an eligible Project's inclusion in the selection of the Final Award Group.

Proposers will not be able to update their Proposals based on any feedback provided by the Company after Proposal submission. Pricing components, as explained in Section 3.9.4, will not be allowed to change, except as allowed at the Best and Final Offer stage noted in Section 4.6.

4.5.1 Generation Facility Technical Model Requirements and Review Process

Proposers selected to the Priority List are required to submit an initial payment of \$15,000[51] to commence with a Generation Facility Technical Model Requirements and Review Process, as prescribed in Appendix B, Attachment 3, Section 3. The \$15,000 payment will be used to offset the costs to perform one cycle of model reviews by Hawaiian Electric and its consultants related to the Generation Facility Technical Model Review Process. Any feedback provided to Proposers is expected to be actioned and resolved by the Proposer prior to the commencement of the Interconnection Requirement Study.

Upon completion of one cycle of review, Proposers will have the option to:

> **Closeout the model review process:** A true-up will be completed upon closure of the process. Any remaining funds may either be refunded to the Proposer or applied to the Interconnection Requirements Study phase. If costs to complete the

[51] The \$15,000 payment is for review of one variation. If a Proposal has multiple variations that advance to the Priority List, only one variation will be required to perform a model review if all variations utilize the same equipment. Otherwise, additional reviews (and payments) may be required for the variations with different equipment. The feedback provided for the one variation selected can be utilized to assist the developer in preparing its models for other Priority List variation(s). The Proposer may request the Company perform a cycle of model reviews on other variations, but each variation request will require a \$15,000 initial payment.

review exceed the $15,000, the Proposer is required to submit payment of the balance within 30 days of the invoice.

Continue review: Upon receiving the first cycle of model review feedback, Proposers have the option to request another cycle of reviews. Proposers selecting this option will be required to submit another $15,000 payment, unless explicitly directed by the Company – such as if the Company determines the remaining balance of the first cycle will cover the estimated cost of another review cycle.

In order to minimize the cost and schedule for all Proposers, as well as study the impacts of the portfolio of projects, portions of the System Impact Study will be performed as a group study, requiring all Proposer models to be an accurate, functional model, and deemed suitable by the Company prior to commencement of the study. The IRS process (Section 5.1) includes a 30-day timeframe for all model reviews to be completed prior to commencement of the group study. Should a Proposer's model not be ready by that time, the Project will be subject to a standalone IRS, which will result in increased cost and potential delays to the Proposer, as the study will have to be undertaken after the group study is completed.

4.5.2 Community Outreach Plan and Cultural Resource Impacts

Within thirty (30) days of notifying Proposers of their selection to the Priority List (which is after the Initial Evaluation where Proposals are scored), the Company will provide feedback to such Proposers on the following portions of their Proposal(s): 1) Community Outreach Plan and 2) Cultural Resource Impacts. Proposers shall respond to any Company requests for clarification and resolve potential issues identified by the Company related to either the Community Outreach Plan or the Cultural Resource Impacts portion of their Proposal. Proposers will not be able to update their Proposals before selection to the Final Award Group based on any feedback provided by the Company on the Community Outreach Plan and/or Cultural Resource Impacts. Pricing components, as explained in Section 3.9.4, will not be allowed to change, except as allowed at the Best and Final Offer stage noted in Section 4.6.

The methods or means of addressing/resolving the potential issues identified by the Company shall be reflected in an updated Community Outreach Plan submitted to the Company within five (5) business days of notification of selection to the Final Award Group (see RFP Section 5.3). Unless the Company otherwise determines, such methods or means of addressing/resolving the potential issues identified by the Company shall be incorporated as additional obligations of the Seller in the negotiated Stage 3 Contract for the Project.

4.6 Best and Final Offer (BAFO)

4.6.1 The Company will solicit a Best and Final Offer from Proposers selected to a Priority List in a technology-based evaluation category. All Proposers selected to the Priority

List, including any Hawaiian Electric Proposals,[52] will have the opportunity to update (downward only)[53] the pricing elements in their Proposal in order to improve the competitiveness of their Proposal prior to being further assessed in the Detailed Evaluation phase. At this point in the process, updates may only be made to the following pricing elements:

- [For PV+BESS, Wind+BESS, Standalone Storage Projects] Lump Sum Payment ($/year) amount
- [For Firm Projects] Capacity Charge payment ($/kW/month) and Energy Charge payment($/kWh) amount.
- [For Hawaiian Electric Proposals] Total Project Capital Costs ($/year), Annual O&M Costs ($/year), ARR ($/year)

Proposers will not be allowed to increase their price[54] but may elect to maintain the same pricing submitted in their original Proposal. Proposers will not be allowed to make any other changes to their Proposal during the Best and Final Offer.

4.6.2 If a Proposer does not propose improvements to their pricing elements during the Best and Final Offer solicitation, the original Proposal pricing elements will be deemed its Best and Final Offer.[55]

4.6.3 To allow Proposers to offer the most competitive pricing while offering protection during these times of market volatility, the Company will allow all Proposals that are selected into the Final Award Group a one-time pricing adjustment of their BAFO-defined Lump Sum Payment amounts for PV and wind Projects and Standalone Storage Projects, and Capacity Charge payment amounts for Firm PPA Projects[56] (or Total Project Capital Costs for the Hawaiian Electric Proposal) based on the difference in the Gross Domestic Producer Price Index between the BAFO submission date and the Commission approval date of the Stage 3 Contract. The price adjustment will be capped to be no greater than a ten percent (10%) adjustment. If there is no inflation during the time period or the index decreases, pricing will remain as bid in the BAFO.

[52] Similar to the Proposal Due Date, if any Hawaiian Electric Proposals or Affiliate Proposals are selected to the Priority List, the Company will require that the Hawaiian Electric Proposal(s) and Affiliate Proposals be submitted a minimum of one (1) day before other Proposals are due.

[53] Proposers will only be allowed to adjust pricing elements downward. No upward adjustment to the pricing elements will be permitted or considered. All other characteristics of the Proposal and Facility capabilities must remain valid and unchanged (e.g., NEP, Contract Firm Capacity, GCOD, etc.)

[54] Proposers will not be allowed to increase the pricing in their Proposals to address interconnection and/or System upgrade costs or for any other reason.

[55] The Company reserves the right, in consultation with the Independent Observer, to adjust the parameters of the BAFO, in the unlikely event that System needs have evolved in a way that the Proposals received do not fully address.

[56] No adjustment will be allowed for the Energy Charge payment amounts for the Firm PPA Projects.

4.7 Detailed Evaluation

The Best and Final Offers of the Priority List Proposals from this RFP will be further assessed in the Detailed Evaluation to determine the Proposals selected to the Final Award Group.

Computer modeling will evaluate the Total Net Cost (Cost and Benefits) of integrating and operating the portfolio onto the Company's System. The portfolio's Total Net Cost will be compared against a reference case that uses the latest inputs and assumptions in the Integrated Grid Planning proceeding (Docket No. 2018-0165), described further below.

All Proposals from the Priority List will be input into the computer model using the Proposal's performance data (i.e., NEP, Contract Firm Capacity, BESS Contract Capacity), and Proposal costs (i.e., Lump Sum Payments, Capacity Charge payments, Energy Charge payments, etc.). An optimal, least-cost resource portfolio will be selected by the computer model, RESOLVE. RESOLVE will be used to determine the optimal type and quantity of resource additions based on a range of constraints such as pricing, GCOD, reliability, operational characteristics and services offered. Note, depending on the number of Proposals on the Priority List, multiple iterations of the computer model may be needed. Additional modeling scenarios or portfolios may also be completed in consultation with the Independent Observer. The evaluation will be based on the Total Net Cost (Costs and Benefits) to the Company of integrating the combination of Priority List Proposals onto the Company's System which includes:

1. The cost to dispatch the Project or combination of Projects and the energy and storage purchased;

2. The fuel cost savings (benefits) and any other direct savings (IPP savings from dispatchable fossil fuel savings, where applicable) resulting from the displacement of generation by the Priority List Proposals, including consideration of round-trip efficiencies for Facilities with storage;

3. The estimated increase (or decrease) in operating cost, if any, incurred by the Company to maintain System reliability; and

4. The cost of imputed debt, if applicable.

The Company may complete additional analyses of the portfolio in consultation with the Independent Observer to verify other operating requirements are met.

The Company will take into account the cost of rebalancing its capital structure resulting from any debt or imputed debt impacts associated with each Proposal (including any costs to be incurred by the Company, as described above, that are necessary in implementing the Proposal). The Company proposes to use the imputed debt methodology published by S&P that is applicable to the Proposal being evaluated. S&P views long-term PPAs as creating fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in generation capacity. By adjusting financial measures to incorporate PPA-fixed obligations, greater comparability of utilities that finance and build generation capacity and those that purchase capacity to satisfy new load are achieved.

During the Detailed Evaluation and before the Proposals advance to the Final Award Group, the Company will perform load flow analyses to determine if certain Projects or combinations of Projects introduce line constraints that will factor into the selection process. This is to address the possibility that even though sufficient available MW capacity was identified for an individual Project, Projects that are in close proximity with each other could introduce additional line constraints. The Projects selected must not have any additional constraints imposed based on the Load Flow Analysis to advance to the Final Award Group. However, the Company reserves the right, in consultation with the Independent Observer, to allow minor modifications and/or downsize the project to a Proposal to avoid such additional constraints or the Proposer can choose to perform interconnection upgrades to eliminate the constraints. If such modification resulted in a reduced size of the Facility, the pricing proposed would also need to be revised. Under no circumstances would a Proposer be allowed to increase its price as a result of such minor modification.

Also in the Detailed Evaluation, other factors will be validated to ensure that the final combination of Projects provides the contemplated benefits that the Company seeks. The Company will evaluate the collateral consequences of the implementation of a combination of Projects, including consideration of the geographic diversity, resource diversity, interconnection complexity, and flexibility and latitude of operation control of the Projects.

The Company may assess additional combinations of Projects if requested by the Independent Observer and if the time and capability exist to perform such analyses.

4.8 Selection of the Final Award Group

Based on the results of the Detailed Evaluation and review of the results with the Independent Observer, the Company will select a Final Award Group from which to begin contract negotiations. The Company intends to select projects that meet the targeted needs and provide customer benefits. As noted above, only firm generation utilizing synchronous generators will be selected to meet the firm renewable generation target and variable renewable dispatchable generation is expected to meet the renewable dispatchable generation target. However, in the event that either target in this RFP is not completely met by Proposals received in either the firm generation or the renewable generation categories, the Company may then, if the Company determines such Proposals can meet the needs identified for such target, consider Proposals responsive to one target to satisfy the needs of the alternate target. All Proposers will be notified at this stage of the evaluation process whether their Proposal is included in the Final Award Group.

Selection to the Final Award Group and/or entering into contract negotiations does not guarantee execution of a Stage 3 Contract.

Up to the selection announcement of the Final Award Group, should any new legislation for renewable energy be enacted that would offer developers further tax credits, the Company reserves the right to require Proposers to provide a downward pricing adjustment reflective of such savings for the benefit of the Company's customers.

Further, if at any time during the evaluation process it is discovered that a Proposer's Proposal contains incorrect or misrepresented information that has a material effect on any of the evaluation processes, including selection of the Priority List or the Final Award Group, the Company reserves the right, at any time prior to submission of the Stage 3 Contract Application with the PUC, in consultation with the Independent Observer, to disqualify the Proposer from the RFP. If discovery of the incorrect or misrepresented information is made after the Company has filed its PUC application for approval of the Stage 3 Contract with the Proposer, the Company will disclose the incorrect or misrepresented information to the PUC for evaluation and decision as to whether such Proposer should be disqualified and the Company's application dismissed.

Following any removal of a Proposal from the Final Award Group, either by disqualification noted immediately above, or via any other removal or withdrawal of a Proposal, including failure to reach agreement to the Stage 3 Contract, the Company, taking into consideration the timing of such removal and the current status of the Company's needs under the RFP, in consultation with and concurrence from the Independent Observer, will review the Priority List to determine (1) if another Proposal should be added to the Final Award Group; or (2) if the remaining Proposals in the Final Award Group should remain unchanged.

Chapter 5: Post Evaluation Process

5.1 Project Interconnection Process

At Proposal Submission

Development of accurate and functional facility technical model is imperative to the successful completion of the IRS, the accuracy of study results, and, by extension, the reliability of the System. Models must be accurate representations of the Facility and its operation. The Company validates the quality of the models and acceptability for the IRS though a model checkout process. Proposers should have developed, executed, tested, and documented results of their models prior to submitting a proposal.

A complete package of Project Interconnection Requirement Data Request worksheets, Project single line and three line diagrams, models (see Appendix B, Attachment 3), and documentation prescribed in Appendix B, Attachment 4, including a report, with plots, documenting that Proposers have tested their models under all scenarios, is required upon Proposal submission. See Section 2.11 of Appendix B.

The models required are set forth in Appendix B, Attachment 4. PSSE Generic models, PSSE User models, and ASPEN models shall be configured to represent all of the functional equipment with settings in place to comply with the Company's Stage 3 Contract performance requirements. These must be checked for functionality by the Proposer or its vendors and consultants prior to submission to the Company (see Appendix B, Attachment 3). Similar and fully accurate PSCAD models shall be submitted in a condition that complies with the PSCAD modeling guidelines provided by the Company.

Post Selection to Final Award Group

Within thirty (30) days after selection of the Final Award Group, final submissions, incorporating any updates, shall be made for the Project data and modelling submittals described above.

The Company will inspect the data packages for general completeness. For any incomplete submissions, a list of missing or non-functional items will be provided. Proposers will be given 15 days to resolve data and modeling deficiencies. The Company, in consultation with the Independent Observer, may remove Proposals from the Priority List or Final Award Group, or may terminate contract negotiations or executed Stage 3 Contracts if their submission requirements are deemed incomplete for the lack of requested models. The Proposal must be complete to begin the IRS process. A formal, technical model checkout will be deferred until a later date when IRS Agreements and deposits are in place, so that the expert subject matter work can be provided by the Company's IRS consultant(s).

Upon notification of selection to the Final Award Group, the Company will provide a draft IRS Agreement for each selected Project, with a statement of required deposit for individual and prorated work as part of an IRS Scope for a System Impact Study that will involve (a) technical model checkout for each project, (b) any considerations that are specific to a particular Project and location, and (c) System impact analyses of the Projects as a group. Interconnection cost and schedule, including cost of any required System upgrades, will be determined in a subsequent Facilities Study.

In order to minimize the cost and schedule for all Proposers, as well as study the impacts of the portfolio of Projects, portions of the System Impact Study will be performed as a group study, requiring all Proposer models to be an accurate, functional model, and deemed suitable by the Company prior to commencement of the study. Within thirty (30) days after selection of the Final Award Group, final submissions, incorporating any updates, shall be made for the Project data and modelling submittals. The IRS process includes a 30-day timeframe, following this model submittal deadline, for all model reviews to be completed prior to commencement of the group study. Should a Proposer's model not be ready by that time, the Project will be subject to a standalone IRS, which will result in increased cost and potential delays to the Proposer, as the study will have to be undertaken after the group study is completed.

The technical model checkouts will be conducted first. Upon identification of any functional problems or deficiencies, corrective action shall be taken immediately and on an interactive basis so that the problems or deficiencies can be resolved within 15 days, including re-submission of data and updated models, or the project shall be deemed withdrawn. At the discretion of the Company and provided that there is a demonstration of good faith action to minimize delay that would affect the schedule for IRS analyses, a second round of model checkout and problem solving may proceed. Thereafter any notice that a Project is deemed withdrawn for lack of completeness shall be final. Subject to consultation with the Independent Observer, failure to provide all requested material within the time(s) specified, or changes to the data provided after the due date(s), shall result in elimination from the Final Award Group.

Proposers shall be responsible for the cost of the IRS, under separate agreements for the System Impact Study and the Facilities Study. The overall IRS will provide information including, but not limited to, an estimated cost and schedule for the required Interconnection Facilities for a particular Project and any required mitigation measures. Proposers will be responsible for the actual final costs of all Seller-Owned Interconnection Facilities and Company-Owned Interconnection Facilities. Upon reviewing the results of the IRS, Proposers will have the opportunity to not move forward with the Project and therefore not complete execution of the Stage 3 Contract in the event that the estimated interconnection costs and schedule for the Project are higher than what was estimated in the Project Proposal. See Section 12.4 of the RDG PPA or the ESPA, or Section 2.2(D) of the Firm PPA.

Proposers should assume, at a minimum, a 12-month process for the completion of the IRS, and the execution and filing of the Stage 3 Contract for approval. Such assumption is dependent on, among other factors, working and finalized models being timely provided for study by Proposers in accordance with the requirements of this Section 5.1.

5.2 Contract Negotiation Process

Within five (5) business days of being notified by the Company of its intent to enter into contract negotiations, Proposers selected for the Final Award Group will be required to indicate, in writing to the Company's primary contact for this RFP, whether they intend to proceed with their Proposals. Proposers who elect to remain in the Final Award Group will be required to keep their Proposal valid through the award period.

As described in Section 5.1 above, a draft IRS Agreement will be provided upon notification of selection to the Final Award Group. The IRS process will commence upon payment of the deposit and execution of the IRS Agreement. Contract negotiations will commence in parallel with the IRS process. The Stage 3 Contract will not be executed until completion of the IRS, and any impacts from the IRS are folded into the Stage 3 Contract. The submission of an executed Stage 3 Contract for PUC approval will take place thereafter.

5.3 Community Outreach and Engagement

The public meeting and comment solicitation process described in this section and Section 29.21 of the Stage 3 Contracts or Section 12.1(L) of the Firm PPA (Community

Outreach Plan) do not represent the only community outreach and engagement activities that can or should be performed by a Proposer.

The Company will publicly announce the Final Award Group no more than five (5) business days after the notification is given to Proposers who are selected to the Final Award Group. Selected Proposers shall not disclose their selection to the public before the Company publicly announces the Final Award Group selection.

By the fifth (5^{th}) business day after the Company notifies a Proposer they were selected, each Proposer shall provide the Company with links to their Project website, which the Company will then post on the Company's website. Each Proposer will launch a Project website that will go-live by that fifth (5^{th}) business day after notification of Final Award Group selection. Information on what should be included on the Project website is identified in Appendix B.

Within five (5) business days of notification of selection to the Final Award Group, Proposers must provide the Company with an updated comprehensive Community Outreach Plan to work with and inform neighboring communities and stakeholders and to provide them timely information during all phases of the Project. The updated Community Outreach Plan shall also incorporate the recommendations of the Company to address potential issues identified in the Company's reviews outlined in Section 4.5.2. The Community Outreach Plan shall include but not be limited to the following information: Project description, identification of Project stakeholders, community concerns and Proposer's efforts to address such concerns, Project benefits, government approvals, Project schedule, plan for reporting construction related updates, labor and prevailing wage commitment, details regarding the intended beneficiaries of the funds (including recipients, and the area(s) in which the funds will be directed), the methods or means of addressing/resolving the potential issues identified by the Company based on its review (as described in RFP Section 4.5.2), and a comprehensive communications plan which factors in monthly Project status updates. Proposers must provide to the Company the name of the individual designated to implement the Project's Community Outreach Plan. The Proposer's Community Outreach Plan shall be a public document identified on the Proposer's Project website for the term of the Stage 3 Contract and made available to the public upon request. If requested by the Company, Proposers shall provide their updated Community Outreach Plan and website information to the Company for review and feedback. If there is no such request by the Company, a Proposer may still provide their updated Community Outreach Plan and website information to the Company for review and feedback. If provided at least thirty (30) days prior to the dates required, the Company will endeavor to review such information and provide feedback on the information before it is made available to the public. Further information and instructions regarding expectations for the Community Outreach Plan can be found in Appendix B, Attachments 5 and 6.

Prior to the execution date of the Stage 3 Contract, Proposers shall also host a public meeting in the community where the proposed Project is to be located. The public meeting shall provide to the community it is situated in, other stakeholders and the general public with: (i) a reasonable opportunity to learn about the proposed Project; (ii) an opportunity to engage in a dialogue about concerns, mitigation measures, and potential community benefits of the proposed Project; (iii) an update regarding the Proposer's cultural impact plan, including any findings made and mitigations identified to-date as part of the Archaeological Literature Review and Field Inspection Report; and (iv) information concerning the process and/or intent for the public's input and engagement, including advising attendees that they will have thirty (30) days from the date of said public meeting to submit written comments to Company and/or Proposer for inclusion in the Company's submission to the PUC of its application for a satisfactory PUC Approval Order and for inclusion on the Proposer's website. The Proposer shall collect all public comments, and then provide the Company copies of all comments received in their original, unedited form. If a Stage 3 Contract is executed by the Proposer and the Company, the Company may submit any and all public comments (presented in its original, unedited form) as part of its PUC application for this Project. Proposers shall notify the public at least three (3) weeks in advance of the meeting. The Company shall be informed of the meeting. The Company has provided Proposers with detailed instructions regarding the community meeting requirement after the selection of the Final Award Group (Attachment 5 to Appendix B). (For example, notice will be published in county and regional newspapers/media, as well as media with statewide distribution. The Proposer will be directed to notify certain individuals and organizations. The Proposer will be provided templates to use for the public meeting notices, agenda, and presentation.) Proposers must also comply with any other requirement set forth in the Stage 3 Contract relating to Community Outreach.

Following the submission of the PUC application for the Project, and prior to the date when the Parties' statements of position are to be filed in the docketed PUC proceeding for the Project, the Proposer shall provide another opportunity for the public to comment on the proposed Project. The Proposer's statement of position filed in the docket associated with the Project will contain an attachment including those comments.

The Proposer shall be responsible for community outreach and engagement for the Project in accordance with the requirements ultimately agreed to in the Stage 3 Contract. The public meeting and comment solicitation process described in this section or in the Stage 3 Contract do not represent the only community outreach and engagement activities that can or should be performed. The Company will also require (monthly/bi-monthly) Project status updates from Proposers to verify the implementation of the Community Outreach Plan and will ensure Proposers provide accessible opportunities for community members and stakeholders to provide public comment as required by the RFP.

5.4 Greenhouse Gas Emissions Analysis

Proposers whose Proposal(s) are selected for the Final Award Group shall cooperate with and promptly provide to the Company and/or Company's consultant(s) upon request all information necessary, in the Company's sole and exclusive discretion, for such consultant to prepare a GHG emissions analysis and report in support of a PUC application for approval of the Stage 3 Contract for the Project (the "GHG Review"). Proposers shall be responsible for the full cost of the GHG Review associated with their Project under a Greenhouse Gas Analysis Letter Agreement between the Proposer and the

Company. The GHG Review is anticipated to address whether the GHG emissions that would result from approval of the Stage 3 Contract and subsequent to addition of the Project to the Company's System are greater than the GHG emissions that would result from the operations of the Company's System without the addition of the Project, whether the cost for renewable, dispatchable generation, and/or energy storage services as applicable under the Stage 3 Contract is reasonable in light of the potential for GHG emissions, and whether the terms of the Stage 3 Contract are prudent and in the public interest in light of its potential hidden and long-term consequences.

5.5 PUC Approval

Any signed Stage 3 Contract resulting from this RFP is subject to PUC approval as described in the applicable Stage 3 Contract.

5.6 Facility In-Service

To facilitate timely commissioning of Projects selected through this RFP, the Company requires the following be included with the 60% design drawings: relay settings and protection coordination study, including fuse selection and AC/DC schematic trip scheme.

For the Company to test the Facility, coordination between the Company and Project is required. Drawings must be approved by the Company prior to testing. The entire Facility must be ready for testing to commence. Piecemeal testing will not be allowed. Communication infrastructure and equipment must be tested by the IPP and ready for operation prior to Company testing.

If approved drawings are not available, or if the Facility is otherwise not test ready as scheduled, the Project may lose its place in the queue, with the Company retaining the flexibility to adjust scheduling as it sees fit. If tests are not completed within the allotted scheduled testing time, the Project will be moved to the end of the Company's testing queue. The IPP will be allowed to cure if successful testing is completed within the allotted scheduled time. No adjustments will be made to Stage 3 Contract milestones if tests are not completed within the original allotted time. Liquidated damages for missed milestones will be assessed pursuant to the Stage 3 Contract.

5.7 Archaeological Literature Review and Field Inspection Report

All Projects selected to a Final Award Group must, within five (5) months of selection, complete and submit to the Company a plan for mitigation from an archaeologist licensed in the State of Hawaii for any archaeological and/or historical sites identified in the completed Archaeological Literature Review of existing cultural documentation filed with the State Historic Preservation Division and a Field Inspection Report.

Any results available at the time of the Community Outreach meeting required prior to Stage 3 Contract execution discussed in Section 5.3 must be presented at that time, along with an update regarding the Proposer's cultural impact plan.

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REQUEST FOR PROPOSALS

FOR

RENEWABLE DISPATCHABLE GENERATION

AND

ENERGY STORAGE

O'AHU

DECEMBER 22, 2022

Docket No. 2017-0352

Appendix A – Definitions

Hawaiian Electric

"Affiliate" means any person or entity that possesses an "affiliated interest" in a utility as defined by section 269-19.5, Hawaii Revised Statutes ("HRS"), including a utility's parent holding company but excluding a utility's subsidiary or parent which is also a regulated utility.

"BESS" means the battery energy storage system.

"BESS Contract Capacity" means the anticipated maximum net instantaneous active power (MW) and maximum energy storage capability (MWh stored that represents a 100% State of Charge) for export to the Point of Interconnection upon Commercial Operations.

"Best and Final Offer" or "BAFO" means the final offer from a Proposer, as further described in Section 4.6 and elsewhere in this RFP.

"Capacity Charge" means the amount to be paid by Company to Seller pursuant to the terms and conditions in the Firm PPA.

"Code of Conduct" means the code of conduct approved by the PUC in Docket No. 03-0372 (Decision and Order No. 23614, August 28, 2007) with respect to a Self-Build Option. An updated code of conduct was submitted to the PUC in 2015-0389 on July 9, 2020.

"Code of Conduct Procedures Manual" or "Procedures Manual" means the manual approved by the PUC, which was put in place to address and to safeguard against preferential treatment or preferential access to information in a Company RFP process. The Procedures Manual is attached as Appendix C to this RFP.

"Commercial Operations" has the meaning set forth in the Stage 3 Contract.

"Community Outreach Plan" is a community outreach and communication plan described in Section 4.3 and 4.4.2 of this RFP.

"Company" means Hawai‘i Electric Light Company, Inc., a Hawai‘i corporation.

"Company-Owned Interconnection Facilities" has the meaning set forth in the Stage 3 Contract.

"Competitive Bidding Framework" or "Framework" means the Framework for Competitive Bidding contained in Decision and Order No. 23121 issued by the Public Utilities Commission on December 8, 2006 in Docket No. 03-0372, and any subsequent orders providing for modifications from those set forth in Order No. 23121 issued December 8, 2006.

"Consumer Advocate" means the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs of the State of Hawai‘i.

"Development Period Security" has the meaning set forth in Section 3.13.1.

"Dispatchable" means the ability to turn on or turn off a generating resource at the request of the utility's system operators, or the ability to increase or decrease the output of a generating resource from moment to moment in response to signals from a utility's Automatic Generation Control

System, Energy Management System or similar control system, or at the request of the utility's system operators.

"Electronic Procurement Platform" means the third-party web-based sourcing platform that will be used for the intake of Proposals and associated electronic information, storage and handling of Proposer information, and communication.

"Eligibility Requirements" has the meaning set forth in Section 4.2 of this RFP.

"Eligible Proposals" means Proposals that meet both the Eligibility and Threshold Requirements.

"Energy Charge" means the amount to be paid by Company to Seller for electric energy delivered to the Company pursuant to the terms and conditions in the Firm PPA.

"Energy Contract Manager" is the primary Company contact for this RFP.

"ESPA" means the Model Energy Storage Purchase Agreement attached as Appendix M to this RFP.

"Evaluation Team" means agents of the Company who evaluate Proposals.

"Facility" has the meaning set forth in the Stage 3 Contract.

"Facilities Study" means a study to develop the interconnection facilities cost and schedule estimate including the cost associated with the design and construction of the Company-owned interconnection facilities.

"Final Award Group" means the group of Proposers selected by the Company from the Priority List, with which the Company will begin contract negotiations, based on the results of the Company's detailed evaluation.

"Firm PPA" means the Model Firm Renewable Dispatchable Generation Power Purchase Agreement attached as Appendix L to this RFP.

"Generation Project" means a Project with a generation component but no energy storage component.

"Greenhouse Gas" or "GHG" are gases that contribute to the greenhouse gas effect and trap head in the atmosphere.

"Guaranteed Commercial Operations Date" or "GCOD" means the date on which a Facility first achieves Commercial Operations.

"Hawai‘i Electric Light" means Hawai‘i Electric Light Company, Inc., a Hawai‘i corporation.

"Hawai‘i Electric Light System" or "System" means the electric system owned and operated by Hawai‘i Electric Light on the island of Hawai‘i (including any non-utility owned facilities) consisting of power plants, transmission and distribution lines, and related equipment for the production and delivery of electric power to the public.

“Hawaiian Electric Companies” or “Companies” means Hawaiian Electric Company, Inc. and its subsidiaries, Hawai‘i Electric Light Company, Inc. and Maui Electric Company, Limited.

“Hawaiian Electric Proposal” means a Proposal submitted by the Company that is responsive to the resource need identified in the RFP, as required by Section VI of the Framework.

“Hawaiian Electric Development Team” means agents of the Company who develop Self-Build proposals.

“Host Community” has the meaning set forth in the Stage 3 Contract.

“HRS” means the Hawai‘i Revised Statutes as of the date of this Request for Proposals.

“Imputed Debt” means adjustments to the debt amounts reported on financial statements prepared under generally accepted accounting principles (“GAAP”). Certain obligations do not meet the GAAP criteria of “debt” but have debt-like characteristics; therefore, credit rating agencies “impute debt and interest” in evaluating the financial ratios of a company.

“Independent Observer” has the meaning set forth in Section 1.4 of this RFP.

“Independent Power Producer” or “IPP” means an entity that owns or operates an electricity generating facility that is not included in the Company’s rate base.

“Interconnection Facilities” means the equipment and devices required to permit a Facility to operate in parallel with, and deliver electric energy to, the Company’s System (in accordance with applicable provisions of the Commission’s General Order No. 7, Company tariffs, operational practices, interconnection requirements studies, and planning criteria), such as, but not limited to, transmission and distribution lines, transformers, switches, and circuit breakers. Interconnection Facilities includes Company-Owned Interconnection Facilities and Seller-Owned Interconnection Facilities.

“Interconnection Requirements Study” or “IRS” means a study, performed in accordance with the terms of the IRS Letter Agreement, to assess, among other things, (1) the system requirements and equipment requirements to interconnect the Facility with the Company’s System, (2) the Performance Standards of the Facility, and (3) an estimate of interconnection costs and project schedule for interconnection of the Facility.

“kV” means kilovolt.

“Land RFI” refers to a Request for Information activity conducted by the Company to identify interested parties willing to make land available for utility-scale renewable energy projects and gather relevant property information.

“LEP” means a levelized energy price ($/MWh) calculated and used for comparison of Proposals based on information provided in the Proposal submission in this RFP.

“Lump Sum Payment” has the meaning set forth in the applicable Stage 3 Contract. It may also be referred to as a monthly Lump Sum Payment to reflect the portion of the payment made each month.

"Mediation" means the confidential mediation conducted in Honolulu, Hawaiʻi, pursuant to and in accordance with the Mediation Rules, Procedures, and Protocols of Dispute Prevention Resolution, Inc. (or its successor) or, in its absence, the American Arbitration Association then in effect.

"MW" means megawatt.

"MWh" means megawatt hour.

"NDA" means the Mutual Confidentiality and Non-Disclosure Agreement attached to this RFP as Appendix E.

"NEP" means Net Energy Potential as set forth in Section 3.10.1.

"Net Nameplate Capacity" means the net maximum instantaneous active power capability of the Facility at the point(s) of interconnection, considering nameplate power rating of energy generating equipment sizing;, expected losses in delivery of power to the point(s) of interconnection, and any project control system involved in managing the delivery of power to the point(s) of interconnection. This value, subject to verification by the Company, will determine how a project is evaluated relative to the terms and requirements of the RFP, including, but not limited to ability to interconnect to a transmission line and validation of the maximum output levels used to calculate the NEP RFP Projection. For the purposes of calculating the NEP RFP Projection it should be assumed all energy is being delivered directly to the point(s) of interconnection from the renewable resource as it is generated and never in excess of the Project's Net Nameplate Capacity, independent of the existence of any storage device. In the applicable Stage 3 Contract, this value will be the default Contract Capacity.

"Non-Price Evaluation Team" means Employees and consultants of the Company who evaluate the Proposal non-price related criteria as set forth in Section 4.4 of this RFP. Non-Price Evaluation Team members will not include any Shared Resources and will be solely made up of Company RFP Team Members.

"O&M" means operation and maintenance.

"Operating Period Security" has the meaning set forth in Section 3.13.1.

"Paired Project" means a Project with both a generation component and an energy storage component.

"Performance Standards" means the various performance requirements and attributes for the operation of the Facility to the Company as set forth in this RFP and the Performance Standards as defined in the respective model Stage 3 Contract.

"Point of Interconnection" has the meaning set forth in the Stage 3 Contract.

"Power Purchase Agreement" or "PPA" means an agreement between an electric utility company and the developer of a renewable energy generation facility to sell the power generated by the facility to the electric utility company.

"Price Evaluation Team" means Employees and consultants of the Company who evaluate the Proposal price related criteria as set forth in Section 4.4 of this RFP. Price Evaluation Team members will not include any Shared Resources and will be solely made up of Company RFP Team Members.

"Priority List" means the group of Proposals selected by Hawaiʻi Electric Light as described in Section 4.5 of this RFP.

"Project" means a Facility proposed to Hawaiʻi Electric Light by a Proposer pursuant to this RFP.

"Proposal" means a proposal submitted to Hawaiʻi Electric Light by a Proposer pursuant to this RFP.

"Proposal Due Date" means the date stated in RFP Schedule, Table 1, Section 3.1 for the Hawaiian Electric Proposal and the IPP and Affiliate Proposals of this RFP.

"Proposal Fee" means the non-refundable fee of $10,000 for each proposal submitted as set forth in Section 1.8 of this RFP.

"Proposer" means a person or entity that submits a Proposal to Hawaiʻi Electric Light pursuant to this RFP.

"Proposer's Response Package" means the form in which the Proposal should be submitted, which is attached as Appendix B to this RFP.

"PUC" means the State of Hawaiʻi Public Utilities Commission.

"RDG PPA" means the Model PV and/or Wind Renewable Dispatchable Generation Power Purchase Agreement attached as Appendix J and Appendix K respectively to this RFP.

"Renewable Portfolio Standards" or "RPS" means the Hawaiʻi law that mandates that the Company and its subsidiaries generate or purchase certain amounts of their net electricity sales over time from qualified renewable resources. The RPS requirements in Hawaiʻi are currently codified in HRS §§ 269-91 through 269-95.

"Request for Proposals" or "RFP" means a request for Proposals issued pursuant to a competitive bidding process authorized, reviewed, and approved by the PUC.

"RFP Schedule" means the schedule set forth in Table 1, Section 3.1 of this RFP.

"Seller" means the entity that the Company is contracting with, as set forth in the Stage 3 Contract.

"Seller-Owned Interconnection Facilities" has the meaning set forth in the Stage 3 Contract.

"Site" means the parcel of real property on which the Facility, or any portion thereof, will be constructed and located, together with any Land Rights reasonably necessary for the construction, ownership, operation and maintenance of the Facility.

"Site Control" has the meaning set forth in Section 4.3 of this RFP.

"Stage 3 Contract" means the applicable contract for that technology – i.e., PV+BESS RDG PPA, Wind+BESS RDG PPA, Firm PPA, or ESPA.

"Standalone Storage Project" means a Project with an energy storage component but no generation component.

"Threshold Requirements" has the meaning set forth in Section 4.3 of this RFP.

"Updated Framework" means the updated Framework for Competitive Bidding which was drafted to be more inclusive of various technologies, and filed on February 12, 2021 in Docket No. 2018-0165.

Any capitalized term not defined in this RFP has the meaning set forth in the Stage 3 Contract.

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REQUEST FOR PROPOSALS

FOR

RENEWABLE DISPATCHABLE GENERATION

AND

ENERGY STORAGE

ISLAND OF O'AHU

DECEMBER 22, 2022

Docket No. 2017-0352

Appendix B – Proposer's Response Package / Project Interconnection Data Request

Hawaiian Electric

1.0 GENERAL INSTRUCTIONS TO PROPOSERS

Sourcing Intelligence®, developed by PowerAdvocate®,[1] is the Electronic Procurement Platform that the Company has licensed and will utilize for the RFP process. All Proposals and all relevant information must be submitted via the Electronic Procurement Platform, in the manner described in this RFP.

Proposers must adhere to the response structure and file naming conventions identified in this Appendix for the Proposer's response package. Information submitted in the wrong location/section or submitted though communication means not specifically identified by the Company will not be considered by the Company.

Proposers must provide a response for every item. If input/submission items in the RFP are not applicable to a specific Proposer or Proposal variation, Proposers must clearly mark such items as "N/A" (Not Applicable) and provide a brief explanation.

Proposers must clearly identify all confidential information in their Proposals, as described in more detail in Section 3.12 Confidentiality of the RFP.

All information (including attachments) must be provided in English. All financial information must be provided in U.S. Dollars and using U.S. credit ratings.

It is the Proposer's sole responsibility to notify the Company of any conflicting requirements, ambiguities, omission of information, or the need for clarification prior to submitting a Proposal.

The RFP will be conducted as a "Sealed Bid" event within Sourcing Intelligence, meaning the Company will not be able to see or access any of the Proposer's submitted information until after the event closes.

1.1 ELECTRONIC PROCUREMENT PLATFORM

To access the RFP event, the Proposer must register as a "Supplier"[2] on Sourcing Intelligence. One Proposal may be submitted with each Supplier registration. Minor variations, as defined in Section 1.8.2 and 1.8.3 of this RFP may be submitted along with the Proposal under the same registration.

If a Proposer is already registered on Sourcing Intelligence, the Proposer may use their current login information to submit their first Proposal. Up to three (3) variations of a Proposal, one of which is the base variation of the Proposal, may be submitted together as a Proposal by following the instructions outlined in this Appendix (see Section 3 and 4 below). If the Proposer chooses to submit more than one Proposal, the Proposer must register as a new "Supplier" on Sourcing Intelligence for each additional Proposal.

Each registration will require a unique username, unique Email address, and unique Company name. Proposers that require multiple registrations to submit multiple Proposals should use the Company name field to represent the Company name and Proposal number (ex: CompanyNameP1). Proposers may use shorthand or clear abbreviations. The unique Email address used to create the PowerAdvocate account does not necessarily have to match the Email address specified in Section 2.2.1 below. For example, if the Proposer is submitting multiple

[1] PowerAdvocate became part of Wood Mackenzie in 2021, but web addresses and support email addresses still reference to PowerAdvocate.

[2] The language in Appendix B sometimes refers to "Energy Contract Managers" as "Bid Event Coordinator" and to "Proposers" as "Suppliers" (Bid Event Coordinator and Supplier are terms used by PowerAdvocate).

Proposals, all of the Proposer's Proposals could specify the same primary point of contact Email address if that is what the Proposer requests contact through for all their proposals.

Proposers can register for an account on Sourcing Intelligence by clicking on the "Registration" button (located in the top right corner of the webpage) on the PowerAdvocate website at the following address: **www.poweradvocate.com**

The Proposer's use of the Electronic Procurement Platform is governed by PowerAdvocate's Terms of Use. By registering as a "Supplier" on the Electronic Procurement Platform, the Proposer acknowledges that the Proposer has read these Terms of Use and accepts and agrees that, each time the Proposer uses the Electronic Procurement Platform, the Proposer will be bound by the Terms of Use then accessible through the link(s) on the PowerAdvocate login page.

Once a Proposer has successfully registered as a "Supplier" with PowerAdvocate, the Proposer shall request access to the subject RFP event from the Company Contact via Email through the RFP Email Address set forth in Section 1.6 of the RFP. The Email request must list the Company Name field and username under which the Proposer has registered with PowerAdvocate. If the Proposer plans to submit multiple Proposals and has registered multiple accounts in accordance with the instructions above, the Email request must contain the Company Name field and username for each account that will be used to submit the Proposals. After being added to the event, the Proposer will see the bid event on their dashboard upon logging into Sourcing Intelligence. Once the RFP event opens, the Proposer may begin submitting their Proposal(s).

After registering and prior to the opening of the RFP, Proposers are encouraged to familiarize themselves with the Electronic Procurement Platform, including tabs and dashboard, and the PowerAdvocate Users Guide (RFP Appendix D), etc. Proposers should note that they will not be able to access any bid documents until the event officially opens.

Proposers may contact PowerAdvocate Support for help with registration or modification of registration if desired. Support is available from 8 AM to 8 PM Eastern Time (2 AM to 2 PM Hawaiʻi Standard Time when daylight savings is in effect) Monday to Friday, except for Holidays posted on the PowerAdvocate website, both by phone (857-453-5800) and by Email (support@poweradvocate.com).

Contact information for PowerAdvocate Support can also be found on the bottom border of the PowerAdvocate website: **www.poweradvocate.com**

Once the RFP event is opened, registered Proposers will have online access to general notices and RFP-related documents via the Electronic Procurement Platform. Proposers should also monitor the RFP Website throughout the RFP event.

1.2 PROPOSAL SUBMISSION PROCEDURES

An Email notification will be sent to all registered Proposers when the event has been opened to receive Proposals.

After logging onto the Electronic Procurement Platform, the RFP will be visible on the Proposer's dashboard with several tabs, including the following:

- "**1. Download Documents:**" Documents stored under this tab are provided for the Proposer's use and information. All documents can be downloaded and/or printed, as required.
- "**2. Upload Documents:**" Proposal submission documents requested in Appendix B must be uploaded using this tab.
- Note that "3. Commercial Data:", "4. Technical Data:", and "5. Pricing Data:" tabs are NOT USED for this event.

Step-by-step instructions for submitting a complete Proposal are provided below:

1. Proposers must upload their Proposal files, including all required forms and files, to submit a complete Proposal. All files must be uploaded before the respective Proposal Due Date (RFP Section 3.1, Table 2).

2. Submit (upload) one consolidated PDF representing your Proposal via the "2. Upload Documents" tab. That Proposal PDF must abide by the format specified in this Appendix B. A MSWord.docx template that outlines the format of this document is available under the "1. Download Documents" tab for the Proposer's use. **Response information must be provided in the order, format, and manner specified in this Appendix B and must clearly identify and reference the Appendix B section number that the information relates to**.
    a. Proposers shall use a filename denoting: CompanyName_Proposal#.pdf. (example: AceEnergy_P1.pdf)

3. Proposal information that cannot be easily consolidated into the PDF file described in Step 2 (such as large-scale drawing files) or files that must remain in native file format (such as computer models and spreadsheets) shall be **uploaded separately but must be referenced from within the main Proposal PDF file** (e.g., "See AceEnergyP1V2_2.5_SiteControlMap.kmz"). Such additional files must follow the naming convention below:
    a. File names must include, in order, Company Name, Proposal number (if more than one Proposal being submitted per Proposer), Variation (if any variations are being submitted), Appendix B section number, and a file descriptor, as shown in the example file name below:
    AceEnergyP1V2_2.5_SiteControlMap.kmz
    Proposers may use abbreviations if they are clear and easy to follow.

4. Upload files using the "**2. Upload Documents**" tab on the Electronic Procurement Platform.
    a. Select "Choose File..." Navigate to and choose the corresponding file from your computer.
    b. For all documents identify the "Document Type" as "Technical Information." (Do not identify any documents as "Commercial and Administrative" or "Pricing.")
    c. "Reference ID" may be left blank.

    There is no limit to the number or size of files that can be uploaded. Multiple files may be grouped into a .zip archive for upload. (Any zipped files must still adhere to the naming directions in #3 above.) When successfully uploaded, documents will appear under the "Bid Submissions" section on the bottom of the tab's page, organized within the "Technical Information" Document Type. Repeat steps a, b, and c, as required for each file upload.

If a file with the same name is uploaded twice, the Platform will provide notification of the duplication and automatically append a unique numerical extension to the Document Name. To delete a file that has been previously uploaded, click on the "X" button in the "Actions" column. Do not upload any files prior to the issuance of the Final RFP.

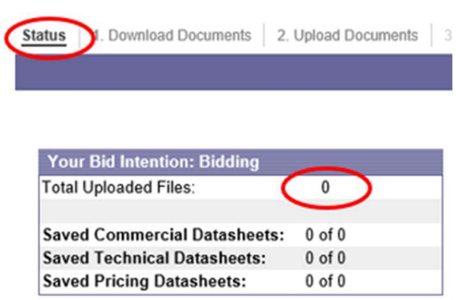
5. The Company will not be responsible for technical problems that interfere with the upload or download of Proposal information. Support is available to answer technical questions about PowerAdvocate's Sourcing Intelligence from 8 AM to 8 PM Eastern Time (2 AM to 2 PM Hawai'i Standard Time when daylight savings is in effect) Monday to Friday, except for Holidays posted on the PowerAdvocate website, both by phone (857-453-5800) and by Email (support@poweradvocate.com).

6. Proposers are strongly encouraged to start early and avoid waiting until the last minute to submit the required information. Proposers are allowed to add, modify, and/or delete documents that have been previously submitted any time prior to the event close deadline. It is the Proposer's responsibility to ensure a complete Proposal is uploaded into PowerAdvocate before the Proposal Due Date.

7. Any questions or concerns regarding the RFP may be submitted to the Company Contact via the RFP Email address provided in Section 1.6 of the RFP. Per RFP Section 1.4.2, the Independent Observer will monitor communication within the bid event. Proposers should include the Independent Observer Email Address when submitting questions to the RFP Email Address. Proposers are responsible for following instructions and uploading documents in their appropriate locations. Documents uploaded in the wrong tab will not be considered by the Company.

1.3 PROPOSAL COMPLETION AND CONFIRMATION PROCEDURES

To confirm the submission of all proposal files, in the "Status" tab on the Electronic Procurement Platform, confirm that the "Total Uploaded Files" is the number of expected files to be included in the submission by checking it against your list of submitted files. Example "Status" tab view:



As stated above in Section 1.2, nothing should be uploaded to the Commercial, Technical or Pricing Datasheet tabs. Documents uploaded there will not be included in your Proposal submission.

1.3.1 **Proposal Fee Delivery Information.** Provide the Proposal Fee submission information for this Proposal. Include:

- The Date the Proposal Fee was sent.
- The delivery service used and the tracking number for the parcel.
- The U.S.-chartered bank name that issued the cashier's check and the check number.

2.0 PROPOSAL (BASE VARIATION) SUMMARY TABLE

Base variation Proposal Summary. If proposal variations are submitted, any changes to the summary information for such variations must be specifically identified in a similar table placed in Section 3 of this Appendix, as applicable.

To be filled out in its entirety by IPP or Affiliate Proposers:

1	**Proposer Name (Company Name)**	
2	**Parent Company/Owner/Sponsor/Business Affiliation/etc.**	
3	**Project Name**	
4	**Net Nameplate Capacity** (MW)[3]	
4a	**Installed Nameplate Capacity: the aggregate sum of the net nameplate active power capabilities of all generator and converter equipment (i.e. storage) installed.**	
5	**Proposed Facility Location, Street Address if available, or what City/Area on the island is it near**	
6	**TMK(s) of Facility Location** (use 9 digits TMK format)[4]	
7	**Point of Interconnection's Circuit or Substation Name**	
7a	**Coordinates for Point(s) of Interconnection (use decimal degrees)**[5]	
8	**Proposal Contract Term** (Years)	
9	**Proposal Guaranteed Commercial Operations Date** (MM/DD/YYYY)	
10	**Does the Project include a Generation Component?** (Yes/No)	
10a	If "yes", what is the **Project Generation Technology**	
10b	[PV+BESS, Wind+BESS Projects] **Net Energy Potential (NEP) Projection for the Facility** (MWh)	
10c	[Firm Projects] **Fuel Source for Generation**	
11	**Does the Project include an Energy Storage Component?** (Yes/No)	
11a	If "yes", what is the **Project Energy Storage Technology**	
11b	**Energy Storage Capability for the Facility** (MW and MWh)	
11c	**Does the Proposal include any federal tax credits in its pricing?** (Yes/No)	

[3] A Project's Net Nameplate Capacity is the net maximum output (MWac) of the Facility at the point(s) of interconnection, whether that maximum is based on: nameplate power rating of energy generating equipment sizing; expected losses in delivery of power to the point(s) of interconnection; and/or any project control system involved in managing the delivery of power to the point(s) of interconnection. This value, subject to verification by the Company, will determine how a project is evaluated relative to the terms and requirements of the RFP, including, but not limited to ability to interconnect to a transmission line. In the applicable Stage 3 Contract, this value will be the default Contract Capacity. For example, in the RDG PPA this is used for the validation of the maximum output levels used to calculate the NEP RFP Projection. For the purposes of calculating the NEP RFP Projection it should be assumed all energy is being delivered directly to the point(s) of interconnection from the renewable resource as it is generated and never in excess of the Project's Net Nameplate Capacity, independent of the existence of any storage device.

[4] Island Number (1 digit); Zone Number (1 digit); Section Number (1 digit); Plat Number (3 digits, add leading zeros if less than 3 digits); Parcel Number (3 digits, add leading zeros if less than 3 digits)

[5] Decimal degrees (YY.YYYYYY, -XXX.XXXXXX) latitude and longitude coordinates of the Point of Interconnection for the project. If there is more than one interconnection point, specify each.

11d	**Is the Project capable of being 100% charged from the grid from the GCOD?** (Yes/No)	
12	**Does the Project have grid-forming capabilities?**	
13	**Does the Project have black start capability?**	
14	**The Proposer hereby certifies that the Project meets all performance attributes identified in Section 2.1 of the RFP?** (Yes/No)	
15	**The Proposer hereby certifies that no single point of failure from the Facility shall result in a decrease of active power measured at the Facility point of interconnection greater than 30 MW.** (Yes/No)	
16	**The Proposer hereby certifies that the Proposal (including its pricing elements) is not contingent upon changes to existing County, State or Federal laws or regulations or certain Stage 3 Contract modifications being accepted.** (Yes/No)	
17	**The Proposer hereby certifies under penalties of perjury that this Proposal has been made in good faith and without collusion or fraud with any other person. As used in this certification, the word "person" shall mean any natural person, business partnership, corporation, union, committee, club, or organization, entity, or group of individuals.** (Yes/No)	
18	**The Proposer hereby acknowledges that the Company reserves the right to select more or less than the full amount of generation solicited in this RFP in the event that specific Hawaiian Electric system needs are revised during the course of the RFP process.** (Yes/No)	
19	**Does the Proposer accept the contract terms identified in the applicable Model Stage 3 Contract in its entirety?** (Yes/No)	
19a	If the response to #19 is "No", **specify the name of the Microsoft Word red-line file that identifies the proposed modifications to the agreement, provided, however, that such proposed modifications shall be limited to targeted revisions to, and not deletions or waivers of, the agreement's terms, conditions, covenants, requirements or representations.**	
20	**The Proposer hereby agrees to provide Development Period Security and Operating Period Security as set forth in the applicable model Stage 3 Contract for this Project.** (Yes/No)	
21	**The Proposer hereby certifies that the Proposer, its parent company, or any affiliate of the Proposer: (1) has <u>not</u> defaulted on a current contract with the Company, unless such default was cured by the contracting Proposer, parent company, or affiliate in an expeditious manner to the satisfaction of the Company; (2) has not had a contract terminated by the Company, which was not reinstated or otherwise superseded by a subsequent contract; or (3) has <u>no</u> pending litigation in which the Proposer, parent company, or affiliate has made claims against the Company which is not subject of a settlement agreement that is currently in effect?** (Yes/No)	
21a	If the response to #21 is "No", **specify what part or parts of #21 prevents the Proposer from stating Yes.**	
22	**Is the Proposer (or any partner of the Proposer) an Affiliate of the Company?** (Yes/No)	
23	**The Proposer hereby certifies under penalties of perjury that it has not shared this Proposal, or any part thereof, with any other Proposer of a Proposal responsive to this RFP.** (Yes/No)	
24	**Has the Proposer contacted the Company and confirmed the available MW capacity at the proposed POI?** (Yes/No)	

24a	**Identify the date/time and title of the email communication confirming the available MW capacity at the proposed POI.**	

IPP or Affiliate Proposal Pricing:

[For PV+BESS, Wind+BESS, and Standalone Storage Projects]

25	**Lump Sum Payment** ($/Year)	

[For Firm Projects only]

26	**Capacity Charge** payment ($/kW/Month)	
27	**Energy Charge** payment[6]**, if any** ($/kWh)	

[6] Also called Guaranteed Variable O&M Rate ($/kWh).

To be filled out in its entirety by any Hawaiian Electric Proposers:

1	**Proposer Name (Company Name)**	
2	**Parent Company/Owner/Sponsor/Business Affiliation/etc.**	
3	**Project Name**	
4	**Net Nameplate Capacity** (MW) [7]	
4a	**Installed nameplate capacity: the aggregate sum of the net nameplate active power capabilities of all generator and converter equipment (i.e. storage) installed.**	
5	**Proposed Facility Location, Street Address if available, or what City/Area on the island is it near**	
6	**TMK(s) of Facility Location** (use 9 digits TMK format)[8]	
7	**Point of Interconnection's Circuit or Substation Name**	
7a	**Coordinates for Point(s) of Interconnection (use decimal degrees)** [9]	
8	**Proposal Contract Term** (Years)	
9	**Proposal Guaranteed Commercial Operations Date** (MM/DD/YYYY)	
10	**Does the Project include a Generation Component?** (Yes/No)	
10a	If "yes", what is the **Project Generation Technology**	
10b	[PV+BESS, Wind+BESS Projects] **Net Energy Potential (NEP) Projection for the Facility** (MWh)	
10c	[Firm Projects] **Fuel Source for Generation**	
11	**Does the Project include an Energy Storage Component?** (Yes/No)	
11a	If "yes", what is the **Project Energy Storage Technology**	
11b	**Energy Storage Capability for the Facility** (MW and MWh)	
11c	**Does the Proposal include any federal tax credits in its pricing?** (Yes/No)	
11d	**Is the Project capable of being 100% charged from the grid from the GCOD?** (Yes/No)	
12	**Does the Project have grid-forming capabilities?**	
13	**Does the Project have black start capability?**	
14	**The Proposer hereby certifies that the Project meets all performance attributes identified in Section 2.1 of the RFP?** (Yes/No)	
15	**The Proposer hereby certifies that no single point of failure from the Facility shall result in a decrease of active power measured at the Facility point of interconnection greater than 30 MW.** (Yes/No)	
16	**The Proposer hereby certifies that the Proposal (including its pricing elements) is not contingent upon changes to existing County, State or Federal laws or regulations or certain Stage 3 Contract modifications being accepted.** (Yes/No)	
17	**The Proposer hereby certifies under penalties of perjury that this Proposal has been made in good faith and without collusion or fraud with any other person. As used in this**	

[7] See footnote 3 above.

[8] Island Number (1 digit); Zone Number (1 digit); Section Number (1 digit); Plat Number (3 digits, add leading zeros if less than 3 digits); Parcel Number (3 digits, add leading zeros if less than 3 digits)

[9] Decimal degrees (YY.YYYYYY, -XXX.XXXXXX) latitude and longitude coordinates of the Point of Interconnection for the project. If there is more than one interconnection point, specify each.

	certification, the word "person" shall mean any natural person, business partnership, corporation, union, committee, club, or organization, entity, or group of individuals. (Yes/No)	
18	**The Proposer hereby acknowledges that the Company reserves the right to select more or less than the full amount of generation solicited in this RFP in the event that specific Hawaiian Electric system needs are revised during the course of the RFP process.** (Yes/No)	
19	**Does the Proposer accept the contract terms identified in the applicable model Stage 3 Contract in its entirety?** (Yes/No)	
19a	If the response to #19 is "No", **specify the name of the Microsoft Word red-line file that identifies the proposed modifications to the agreement, provided, however, that such proposed modifications shall be limited to targeted revisions to, and not deletions or waivers of, the agreement's terms, conditions, covenants, requirements or representations.**	
20	**The Proposer hereby certifies under penalties of perjury that it has not shared this Proposal, or any part thereof, with any other Proposer of a Proposal responsive to this RFP.** (Yes/No)	
21	**Has the Proposer contacted the Company and confirmed the available MW capacity at the proposed POI?** (Yes/No)	
21a	**Identify the date/time and title of the email communication confirming the available MW capacity at the proposed POI.**	

Hawaiian Electric Cost Information:

22	**Year** (YYYY)	**Project Capital Cost** ($)
23	**Year** (YYYY)	**O&M Cost** ($)
24	**Year** (YYYY)	**Annual Revenue Requirement** ($)

Extend the table for questions 22, 23, and 24 for as many years as needed.

2.1 REQUIRED FORMS ACCOMPANYING PROPOSAL PDF

The following forms must accompany each proposal, attached to the Proposal PDF, and uploaded via the "2. Upload Documents" tab:

- Document signed by an officer or other Proposer representative **authorizing the submission** of the Proposal.
- Fully executed Stage 3 **Mutual Confidentiality and Non-Disclosure Agreement** (Appendix E to the RFP, may be downloaded from the "1. Download Documents" tab in the Electronic Procurement Platform).
- **Certificate of Vendor Compliance** for the Proposer.
    - **Certificate of Good Standing** for the Proposer and **Federal and State tax clearance certificates** for the Proposer may be provided in lieu of the Certificate of Vendor Compliance.
- **Certification of Counsel for Proposer**, if applicable. (See Appendix B Attachment 1.)
- **Email from the Company** verifying the available MW capacity at the POI and/or available substation accommodation for the interconnection of the Project.
- Completed applicable **Project Interconnection Data Request worksheet** for the proposed technology and, **project diagram(s). Models for equipment and controls, list(s)** identifying components and **respective files** (for inverters and power plant controller), and **complete documentation with instructions** as specified in the Data Request worksheet shall be submitted within the respective timeframes specified in Section 5.1 of the RFP.[10] (See Section 2.11.1 below)
- [For Hawaiian Electric Proposals Only] **Hawaiian Electric Proposal Team Certification Form.** See Appendix G Attachment 1.
- [For Hawaiian Electric Proposals Only] **Revenue Requirements Worksheets** that support the annual revenue requirements estimates shall be submitted. A starter revenue requirements template file can be requested by the Hawaiian Electric Proposal Team via email to the RFP Email Address once the RFP event opens. The revenue requirements worksheets submitted will be customized by the Hawaiian Electric Proposal Team to reflect the details of the Project's Proposal. All assumptions used will be reflected in an assumptions input tab.

2.2 PROPOSAL SUMMARY/CONTACT INFORMATION

2.2.1 Provide a **primary point of contact** for the Proposal being submitted:

- Name
- Title
- Mailing Address
- Phone Number
- Email Address – this will be the official communication address used during the RFP process

[10] If the Models, lists, respective files and complete documentation are not submitted with the Proposal upload, they shall be submitted via PowerAdvocate's Messaging as attachments within the respective timeframes specified in Section 5.1 of the RFP.

2.2.2 **Executive Summary of Proposal.** The executive summary must include an approach and description of the important elements of the Proposal, including variation descriptions if variations to the base variation are being submitted. Refer to Section 1.8.2 and 1.8.3 of the RFP for an explanation of minor variations allowed.

If variations to the base variation are proposed, a **table summarizing the differences between all variations** shall be created and included in this section.

2.2.3 **Pricing information.** Pricing information must be filled out in the Section 2.0 Proposal Summary Table above. If variations to the base variation are proposed, each variation's pricing summary must be identified in a similar pricing table in Sections 3, 4, and 5 as applicable. Proposers must provide pricing information only in those table sections – do not embed pricing information in any other portion of the Proposal PDF. [**For Hawaiian Electric Proposals Only**] Cost information is allowed in the Revenue Requirements Worksheet that supports the annual revenue requirements estimates.

2.2.4 Provide a **high-level overview of the proposed Facility**, including at a minimum the following information:

- Installed Nameplate Capacity (MW_{AC} and MW_{DC})
- Net Nameplate Capacity of the Facility at the Point(s) of Interconnection (MW_{AC}) (see Section 2.0 for definition)
- Identified available MW capacity at the Point(s) of interconnection (MW_{AC}).
    - Identify the communication from where the available MW capacity value was acquired (e.g., Company's response to Proposer's inquiry on X date/time).
- Identify all System upgrades the Proposal includes to allow Project to interconnect to System above the identified available MW capacity.
    - Identify the communication from where the System upgrade information was acquired (e.g., Company's response to Proposer's inquiry on X date/time).

Projects that include a generation component must specify:

- Technology Type of Generation
- Number of Generators
- Rated Output of each Generator
- Generator Facility Design Characteristics
- Fuel Source for Generation

Generation projects that include a storage component or stand-alone storage projects must specify:

- Technology Type of Storage (e.g., lithium ion battery)
- Interconnection type (AC or DC)
- BESS Contract Capacity (MW / MWh), as defined in the applicable contract
- Operational Limitations, such as, but not limited to: grid charging limits (with respect to ITC), energy throughput limits (daily, monthly, annually), Stage of Charge ("SOC") restrictions (min/max SOC while at rest (not charging/discharging)), etc. Proposed Operational Limits cannot be in conflict with the energy discharge requirement in the RFP's Section 1.2 Scope of the RFP. If such a conflict is identified, the Proposal may be disqualified.

- Round Trip Efficiency ("RTE"). Specify a single value (percentage) that the Facility is required to maintain throughout the term of the applicable contract. The RTE must consider and reflect:
    - the technical requirements of the Facility (as further set forth in the applicable contract);
    - that the measurement location of charging and discharging energy is at the Point of Interconnection;
    - electrical losses associated with the point of interconnection measurement location;
    - any auxiliary and station loads that need to be served by BESS energy during charge and discharge that may not be done at BESS Contract Capacity or over a fixed duration; and
    - that the data used to validate the RTE will be captured during a full charge cycle (0%-100% SOC) directly followed by a full discharge cycle (100%-0% SOC).
- Number of charge/discharge cycles per year the storage component is capable of
- Allowed Losses (kWh/24-hour period)
- Describe any augmentation plans for the storage component to maintain the functionality and characteristics of the storage during the term of the applicable contract. Include any expected interval of augmentation (months/years).
- Estimated useful life of the storage component (including augmentation if used) (years)
- For generation coupled with energy storage, described the Allowed Percentage of Storage Component's charging that can come from the System Grid, if any, and any conditions of charging (when, percentage of annual total energy input, etc.)

Firm generation projects that operate on fuel must:

- Specify if the Proposer agrees to commit to provide the fuel for the entire proposed term of the Firm PPA? (yes/no)
- Provide a guaranteed heat rate curve for the Facility must be provided with your Proposal. The guaranteed heat rate curve must be specified as a three-term second-order polynomial.
- Specify and describe any minimum monthly/quarterly/annual fuel purchases required in your fuel contract, or specify if no minimum fuel purchase is required.
- Specify and describe any minimum loads or minimum up-times that are driven by the technical and operational capabilities of your Facility, or specify if there is no minimum.
- Fuel storage design and fuel storage plan must be provided that will ensure sufficient fuel for unconstrained dispatch and fuel storage.
    - Include Fuel Floor Requirement Calculation (see Section 1.2.3 of the RFP for the calculation)
    - Confirm 30 days of fuel and necessary consumables on island based on normal expected operation.[11] Fuel may be owned or under guaranteed contract and stored onsite or offsite but in all cases must be on island; reserve fuel may be any fuel the developer is permitted to consume.

[11] The Grid Needs Assessment information provided in App. I of the RFPs can be used to estimate the future normal expected operation for initial fuel supply planning purposes. Over the term of the Project, the future normal expected operation shall be based upon (i) the average level of Company Dispatch during the previous six (6) months and (ii) the expected level of Company Dispatch during the following month as indicated by Company.

    - Provide a fuel management plan that guarantees fuel and necessary consumables stored offsite will be delivered to the Project site, particularly during an emergency event when fuel is required.
- For all projects other than biofuel, provide evidence that the fuel will be secured for the duration of the Firm PPA term. For biofuel source Projects, provide evidence of a fuel supply for at least the first 3 years of the Firm PPA term.
- Provide an approximate number of days per year of planned maintenance.
- Provide all applicable operational constraints known such as, but not limited to, those for environmental compliance. (e.g. hot/cold start times to full output, start-up fuel requirements, start-up and shut-down sequence, limitation on number of start-ups/shutdowns per day, operational constraints due to noise restrictions, minimum/maximum run hour requirements, minimum up time, minimum down time, etc.)
- Provide your Facility's ramp rate (MW/min) or point to where information is located if provided in another part of your Proposal.
- For Biofuel source Projects provide a biofuel price forecast with your Proposal.

2.3 FINANCIAL

Provide the following financial information identified below. As specified in the General Instructions in Section 1.0 above, all information (including attachments) must be provided in English, be provided in U.S. Dollars and use U. S. credit ratings.

2.3.1 Identification of Equity Participants

2.3.1.1 Who are the **equity participants** in the Project (or the equity partners' other partners)?

2.3.1.2 Provide an **organizational structure** for the Proposer including any general and limited partners and providers of capital that identifies:

- Associated responsibilities from a financial and legal perspective
- Percentage interest of each party

2.3.2 Project Financing

2.3.2.1 **How will the Project be financed** (including construction and term financing)? Address at a minimum:

- The Project's projected financial structure
- Expected source of debt and equity financing

2.3.2.2 [For IPP and Affiliate Proposals] Identify all **estimated development and capital costs** for, at a minimum:

- Equipment
    - Identify the manufacturer and model number for all major equipment
- Construction
    - Identify and breakdown what is included in this category and any assumptions made
- Engineering

- Seller-Owned Interconnection Facilities
  - Identify and breakdown what is included in this category and any assumptions made
- Company-Owned Interconnection Facilities
  - Identify and breakdown what is included in this category and any assumptions made, including:
    - Company costs per Appendix H
    - Proposer's estimated costs (unless identified in another category)
- System upgrades necessary to interconnect Project to existing transmission line/substation
  - Identify and breakdown what is included in this category and any assumptions made, including:
    - Proposer's estimated costs for all System upgrades identified in Company's feedback of upgrades required for Project interconnection.
    - Proposer's estimated costs for all System upgrades beyond what was identified in Company's feedback.
- Land
- Annual O&M
- (For Projects that include a storage component) Specify a percentage of the total project cost that is estimated to be attributed to the storage functionality of the Facility. As the storage functionality is treated as a lease, the Company will use the percentage for its preliminary calculation of the lease liability only. This percentage requested for the Company's accounting purposes does not affect nor alter the liquidated damage provisions of the PPA, as those provisions reflect the benefit the Company seeks from the Project's storage functionality.

[For Self-Build Only] Identify all **estimated development and capital costs** for, at a minimum:

- Facility (including any generation and storage components)
- Outside Services
- Interconnection
- Overhead Costs
- Allowance for Funds Used During Construction
- Annual O&M
- Specify the percentage of the total cost associated with the storage component of the Facility
- (For Projects that include a storage component) Specify a percentage of the total project cost that is estimated to be attributed to the storage functionality of the Facility. As the storage functionality is treated as a lease, the Company will use the percentage for its preliminary calculation of the lease liability only. This percentage requested for the Company's accounting purposes does not affect nor alter the liquidated damage provisions of the PPA, as those provisions reflect the benefit the Company seeks from the Project's storage functionality.

2.3.2.3 Discuss and/or provide **supporting information on any project financing guarantees**.

2.3.2.4 Describe any **written commitments obtained from the equity participants**.

2.3.2.5 Describe any **conditions precedent to project financing**, and the Proposer's plan to address them, other than execution of the Stage 3 Contract or any other applicable project agreements and State of Hawaii Public Utilities Commission approval of the Stage 3 Contract and other agreements.

2.3.2.6 Provide any **additional evidence to demonstrate that the Project is financeable**.

2.3.3 Project Financing Experience of the Proposer

Describe **the project financing experience of the Proposer** in securing financing for projects of a similar size (i.e., no less than two-thirds the size) and technology as the one being proposed including the following information for any referenced projects:

- Project Name
- Project Technology
- Project Size
- Location
- Date of Construction and Permanent Financing
- Commercial Operations Date
- Proposer's Role in Financing of the Project
- Off-taker
- Term of the Interconnection Agreement
- Financing Structure
- Major Pricing Terms
- Name(s) of Finance Team Member(s); Time (i.e., years, months) worked on the project and Role/Responsibilities

2.3.4 Evidence of the Proposer's Financial Strength

2.3.4.1 Provide **copies of the Proposer's audited financial statements** (balance sheet, income statement, and statement of cash flows):

- Legal Entity
  - Three (3) most recent fiscal years
  - Quarterly report for the most recent quarter ended
- Parent Company
  - Three (3) most recent fiscal years
  - Quarterly report for the most recent quarter ended

2.3.4.2 Provide the **current credit ratings** for the Proposer (or Parent Company, if not available for Proposer), affiliates, partners, and credit support provider:

- Standard & Poor's
- Moody's
- Fitch

2.3.4.3 Describe any **current credit issues** regarding the Proposer or affiliate entities raised by rating agencies, banks, or accounting firms.

2.3.4.4 Provide any **additional evidence that the Proposer has the financial resources and financial strength** to complete and operate the Project as proposed.

2.3.5 Provide **evidence** that the Proposer can **provide the required securities**

2.3.5.1 Describe the Proposer's **ability (and/or the ability of its credit support provider) and proposed plans to provide the required securities** including:

- Irrevocable standby letter of credit
- Sources of security
- Description of its credit support provider

2.3.6 Disclosure of Litigation and Disputes
Disclose any **litigation, disputes, and the status of any lawsuits or dispute resolution** related to projects owned or managed by the Proposer or any of its affiliates.

2.3.7 State to the best of the Proposer's knowledge: Will the Project result in **consolidation** of the Developer entity's finances onto the Company's financial statements under FASB 810. **Provide supporting information** to allow the Company to verify such conclusion.

2.4 CONTRACT EXCEPTIONS

2.4.1 **State whether the Proposer accepts the contract terms identified in the model Stage 3 Contract** in its entirety or if modifications to the model agreements are proposed. If Proposers elect to propose modifications to the applicable Stage 3 Contract, **identify the name of the Microsoft Word red-line file** in the proposal submission that offers the proposed modifications to the model language that the Proposer is agreeable to.

2.4.2 Proposers electing to propose modifications must **provide a Microsoft Word red-line version of the applicable Stage 3 Contract** identifying specific proposed modifications to the model language that the Proposer is agreeable to and a detailed explanation and supporting rationale for each modification. General comments, drafting notes and footnotes such as "parties to discuss" are unacceptable and will be considered non-responsive.

Proposers that do not upload redlines of the applicable Stage 3 Contract with their Proposal submission will be deemed to have accepted the Model Stage 3 Contract in its entirety. If no modifications are proposed, please state in this section "no modifications to the Model Stage 3 Contract".

As set forth in RFP Section 3.8.6.1, proposed modifications to the Stage 3 Contract will be subject to negotiation between the Company and the Final Award Group and should not be assumed to have been accepted either as a result of being selected to the Final Award Group or based on any previously executed PPA.

2.5 SITE INFORMATION

2.5.1 The Proposal must demonstrate that the Proposer has Site Control for all real property required for the successful implementation of a specific Proposal at a Site not controlled by the Company, including any Interconnection Facilities for which the Proposer is responsible. In addition, developmental requirements and restrictions such as zoning of the Site and the status of easements must be identified. **Proposer must provide documentation set forth in RFP Section 4.3 to prove Site Control.**

2.5.2 Provide a **map of the Project site** that clearly identifies:

- Location of the parcel on which the site is located
- Tax map key number (9-digit format: Island Number (1 digit), Zone Number (1 digit), Section Number (1 digit), Plat Number (3 digits, add leading zeros if less than 3 digits), Parcel Number (3 digits, add leading zeros if less than 3 digits)
- Site boundaries (if the site does not cover the entire parcel)
- Total acreage of the site
- Point(s) of Interconnection
- Grid Connection Point(s)
- Relationship of the site to other local infrastructure
- Existing easements encumbering the parcel on which the site is located

2.5.3 Provide a **site layout plan** which illustrates:

- Proposed location of all equipment
- Proposed location of all facilities on the site, including any proposed line extensions

2.5.4 Describe the **Interconnection route** and include:

- Site sketches of how the facility will be interconnected to the Company's System (above-ground and/or underground).
- Identify the approximate latitude and longitude of the proposed Point of Interconnection, in decimal degrees format, to six (6) decimal places.
- Description of the rationale for the interconnection route.

2.5.5 Identify **any rights-of-way or easements** that are required for access to the site or for interconnection route:

- Describe the status of rights-of-way or easement acquisition.
- Describe the detailed plan for securing the necessary rights-of-way or easement, including the proposed timeline and any evidence of any steps taken to date. Proposers must provide a credible and viable plan for obtaining such rights-of-way or easement(s), including the proposed timeline, the identification of all steps necessary to obtain such right-of-way or easement(s), and evidence of any steps taken to date. In addition, developmental requirements and restrictions such as zoning of the Site and the status of easements must be identified.

2.5.6 Provide the following information related to **land use and impervious cover**[12] of the proposed Project:

[12] As defined by the EPA (8 Tools of Watershed Protection in Developing Areas | Watershed Academy Web | US EPA), impervious cover is "the sum total of all hard surfaces within a watershed including rooftops, parking lots, streets, sidewalks, driveways, and surfaces that are impermeable to infiltration of rainfall into underlying soils/groundwater." For purposes of evaluation, PV panels shall be considered impervious.

- **Land use map** including current zoning of the proposed Project site and adjacent properties; indicate percentage of the proposed Project site for each zoning type identified.
- **Map depicting existing impervious cover** of the proposed Project site; must include the current percentage of impervious cover of the utilized area for the proposed Project.
- **Map depicting final impervious cover** of the proposed Project site; must include the proposed percentage of impervious cover of the utilized area for the proposed Project.
    - In calculations, Proposer must use a consistent area as the base (denominator) between percentages for existing and final impervious cover.
- If the proposed Project is on reclaimed land, such as brownfield,[13] included a **complete description of the reclaimed land and any current land use restrictions**.

2.6 ENVIRONMENTAL COMPLIANCE AND PERMITTING PLAN

Scoring of proposals for the non-price evaluation criteria of this section will be based on the completeness and thoroughness of responses to each of the criteria listed below. The Company recommends that each Proposal incorporate the list below as an outline together with complete and thorough responses to each item in the list. Proposals that closely follow this recommendation will typically be awarded higher scores than proposals that do not.

2.6.1 Describe your **overall land use and environmental permits and approvals strategy** and approach to obtaining successful, positive results from the agencies and authorities having jurisdiction, including:

- Explanation of the conceptual plans for siting
- Studies/assessments
- Permits and approvals
- Gantt format schedule which identifies the sequencing of permit application and approval activities and critical path. (Schedule must be in MM/DD/YY format.)

2.6.2 Discuss the **city zoning and state land use classification**:

- Identify present and required zoning and the ability to site the proposed Project within those zoning allowances.
- Identify present and required land use classifications and the ability to site the proposed Project within those classifications.
- Provide evidence of proper zoning and land use classifications for selected site and interconnection route.
- If changes in the above are required for the proposed Project, provide a plan and timeline to secure the necessary approvals.

2.6.3 Identify all required discretionary and non-discretionary **land use, environmental and construction permits, and approvals** required for development, financing, construction, and operation of the proposed Project, including but not limited to zoning changes, Environmental Assessments, and/or Environmental Impacts Statements.

[13] As defined by the EPA (Overview of EPA's Brownfields Program | US EPA), brownfield is "a property, the expansion, redevelopment, or reuse of which may be complicated by the presence or potential presence of a hazardous substance, pollutant, or contaminant."

Provide a **listing of such permits and approvals** indicating:

- Permit Name
- Federal, State, or Local agencies and authorities having jurisdiction over the issuance
- Status of approval and anticipated timeline for seeking and receiving the required permit and/or license
- Explanation of your basis for the assumed timeline
- Explain any situation where a permit or license for one aspect of the Project may influence the timing or permit of another aspect (e.g. a case where one permit is contingent upon completion of another permit or license), if applicable.
- Explain your plans to secure all permits and approvals required for the Project.

2.6.4 Provide a **preliminary environmental assessment of the site** (including any pre-existing environmental conditions) and potential short- and long-term **impacts** associated with, or resulting from, the proposed Project – including direct, indirect, and cumulative impacts associated with development, construction, operation, and maintenance of the proposed Project in every area identified below. Discuss if alternatives have been or will be considered. The assessment shall also include Proposer's short- and long-term plans to mitigate such impacts and explanation of the mitigation strategies for, but not limited to, each of the major environmental areas as presented below:

- Natural Environment
  - Air quality
  - Biology (Natural habitats and ecosystems, flora/fauna/vegetation, and animals, especially if threatened or endangered)
  - Climate
  - Soils
  - Topography and geology
- Land Regulation
  - Land Uses, including any land use restrictions and/or pre-existing environmental conditions/contamination
  - Flood and tsunami hazards (including the site's flood zone based on the Hawaii Department of Land and Natural Resources flood map)
  - Noise
  - Roadways and Traffic
  - Utilities
- Socio-Economic Characteristics
- Aesthetic/Visual Resources
- Solid Waste
- Hazardous Materials
- Water Quality
- Public Safety Services (Police, Fire, Emergency Medical Services)
- Recreation
- Potential Cumulative and Secondary Impacts

2.6.5 Provide a **decommissioning plan**, including:

- Developing and implementing program for recycling to the fullest extent possible, or otherwise properly disposing of installed infrastructure, if any, and
- Demonstrating how restoration of the Site to its original ecological condition is guaranteed in the event of default by the Proposer in the applicable Site Control documentation.

2.7 CULTURAL RESOURCE IMPACTS

2.7.1 Provide a **proposal to ensure cultural sites are identified and carefully protected** as part of a cultural impact plan as it pertains to the Project Site and interconnection route. This proposal must include at a minimum:

- An initial analysis that identifies:
  1) valued cultural, historical, or natural resources in the area in question, including the extent to which traditional and customary native Hawaiian rights are exercised in the area;
  2) the extent to which those resources – including traditional and customary native Hawaiian rights – will be affected or impaired by the proposed action; and
  3) the feasible action, if any, to be taken to reasonably protect any identified cultural, historical, or natural resources in the area in question, and the reasonable protection of traditional and customary native Hawaiian rights in the affected area.
- Proposer's experience with cultural resource impacts on past projects
- Consultant's experience with cultural resource impacts on past projects (name, firm, relevant experience)
- Status of the cultural impact plan (including, but not limited to: Cultural Impact Assessment, Cultural Landscape Study, Cultural Resource Management Plan, Ethnographic Survey, Consultation on Section 106 Process, and/or Traditional Cultural Property Studies)

2.7.2 Archaeological Literature Review of existing cultural documentation filed with the State Historic Preservation Division and a Field Inspection Report which identifies any known archaeological and/or historical sites within the project area. If sites are found, Proposers must provide a plan for mitigation from an archaeologist licensed in the State of Hawaii.

2.8 COMMUNITY OUTREACH

Gaining community support is an important part of a Project's viability and success. An effective Community Outreach Plan will call for early meaningful communications with stakeholders and will reflect a deep understanding and respect for the community's desire for information. The public meeting and comment solicitation process described in Section 5.3 of the RFP is intended to support that premise and the Commission's desire to increase bid transparency within the RFP process. When developers neglect to demonstrate transparency and a willingness to engage in early and frequent communication with Hawaii's communities, costly and timely challenges to their projects have resulted. In some instances, projects have failed. Incorporating transparency during the competitive bidding phase may seem unconventional, but it has become an essential community expectation. Developers must share information and work with communities to address concerns through careful listening, thoughtful responsiveness, and a commitment to respect the environmental and cultural values of Hawaiʻi. Comprehensive and proactive community outreach will be imperative in order to compose a Community Benefits Package that is relevant and meaningful to the project's host community.

2.8.1 Provide a **detailed Community Outreach Plan** to work with and inform neighboring communities and stakeholders and to provide them timely information during all phases of the Project. The plan shall address, but not be limited to, the following items:

- Project description
- Community scoping
- Project benefits
- Government approvals
- Development process
- Identification of communities and other stakeholders that may be affected by the proposed Project:
  - How will they be affected?
  - What mitigation strategies will the Proposer implement?
- Community benefits package (documentation):
  - A documented community benefits package highlighting the distribution of funds must be developed by Proposers for Hawaiian Electric's review and approval.
    - This document will be made public on each Proposer's website and must demonstrate how funds will directly address needs in the host community to benefit community members.
    - The community benefits package must include documentation of each Proposer's community consultation and input collection process to define host community needs and selection of non-profit(s) to address needs through community-based programs.
    - Preference will be given to Proposers that commit to setting aside a larger amount or commit to providing other benefits (including but not limited to creating local jobs, payment of prevailing wages, or improving community infrastructure).
  - Specify the amount of funds ($) that the Proposer will commit on an annual basis to provide as community benefits. As described in Section 4.4.2 of the RFP, at a minimum, Proposers should commit to setting aside at least $3,000 per MW per year for community benefits.
  - These shall be donated to address specific needs identified by the host community, or to a 501(c)(3) not-for-profit community-based organization(s) to directly address host community-identified needs.
  - Provide details regarding the intended beneficiaries of the funds, including recipients, and the area(s) in which the funds will be directed.
  - Proposers may choose to identify and select an eligible non-profit organization to serve as the administrator responsible for ensuring the project's community benefit is appropriately disbursed for the duration of the contract term. Should a Proposer need an example of the use of a community benefit funding host, the Company will provide such example(s) upon request.
    - If Proposers opt to work with a 501(c)(3) non-profit organization(s) to host and distribute community benefit funding, the names of the organization(s) must be provided with documentation 90 calendar days upon signing of the applicable Stage 3 Contract.
      - Name of non-profit organization(s)
      - Letter from non-profit organization, signed by organization's executive and Board Chair agreeing to serve as community benefit fund administrator for the duration of the contract term
      - Relevant experience of non-profit
      - Years of existence of non-profit

    - Any other community benefits (in addition to community funding) that will provide direct benefit to the Project's host community
- Comprehensive Communications Plan, including a detailed community outreach schedule, with affected communities and the general public regarding the proposed Project:
    - Describe frequency of communication with identified stakeholders
    - Provide timeline
    - Provide source of information
    - Identify communication outlets
    - Describe opportunities, if any, for affected communities and general public to provide the developer with feedback and comments on the proposed Project
    - Describe how community feedback and comments, as well as responses to community questions and concerns, will be documented and shared with the community.
    - Project schedule
    - Name of individual designated to implement the Project's Community Outreach Plan
- Construction related updates
    - Plan for reporting construction schedules and activities, including resulting impacts (ex. traffic, noise, and dust) and proper mitigation plans beginning at least one month prior to the start of scheduled work
- Local labor and prevailing wage commitment (if any)
- Outreach experience

Proposers are reminded of RFP Section 3.4.2 including the provision of Proposals must provide all referenced material if it is to be considered during the Proposal evaluation.

2.8.2 Provide any **documentation of local community support or opposition** including any letters from local organizations, newspaper articles, or communications from local officials.

2.8.3 Provide a **description of community outreach efforts** already taken or currently underway, including the names of organizations and stakeholders contacted about the proposed Project and indicate if contact was successful.

2.8.4 Describe any anticipated or negotiated investment in the community and other **community benefits** that the Proposer proposes to provide in connection with the Project, along with an estimated value of the community benefits in dollars (including the cost to Proposers providing the benefits and supporting details on how those costs and benefits were derived).

2.8.5 All Proposers selected to the Final Award Group must display the below table of information on their website as described in Section 5.3 of the RFP to provide communities Project information that is of interest to them in a standard format. All information in this table must be included in all community presentations in addition to the Proposer's project website.

PROJECT SUMMARY

*	Proposer Name (Company name)	
*	Parent Company/Owner/Sponsor/Business Affiliation/etc.	
*	Project Name	
*	Project Capacity (MW) (must match Proposal information)	

*	Proposed Facility Location, Street Address if available, or what City/Area on the island it is near	
*	TMK(s) of Facility Location (must match Proposal information)	
*	Point of Interconnection's Circuit (must match Proposal information)	
*	Project Description (in 200 words or less)	*(A description that includes information about the project that will enable the community to understand the impact that the Project might have on the community.)*
*	Project site map	*(provide a map similar to what was provided in Section 2.5.2)*
*	Site layout plan	*(provide a layout similar to what was provided in Section 2.5.3)*
*	Interconnection route	*(provide a map of the route similar to what was provided in Section 2.5.4)*
Environmental Compliance and Permitting Plan		
*	Overall land use and environmental permits and approvals strategy	*(provide information in level of detail as provided in Section 2.6.1)*
*	Gantt format schedule which identifies the sequencing of permit applications and approval activities and critical path. Schedule must be in MM/DD/YY format)	*(provide information in level of detail as provided in Section 2.6.1)*
*	City Zoning and Land Use Classification	*(provide information in level of detail as provided in Section 2.6.2)*
*	Discretionary and non-discretionary Land use, environmental and construction permits and approvals	(*provide information in level of detail as provided in* Section 2.6.3)
*	Listing of Permits and approvals	(*provide information in level of detail as provided in* Section 2.6.3)
*	Preliminary environmental assessment of the Site (including any pre-existing environmental conditions)	(*provide information in level of detail as provided in* Section 2.6.4)
Cultural Resource Impacts		
*	Proposer's updated Community Outreach Plan must include a plan that (1) identifies any cultural, historic or natural resources that will be impacted by the Project (2) describes the potential impacts on these resources and (3) identifies measures to mitigate such impacts.	(*provide information in level of detail as provided in* Section 2.7)
Community Outreach		

*	Detailed Community Outreach Plan	*(provide key information from Community Outreach Plan as specified in Section 2.8.1 or provide a link to updated comprehensive Community Outreach Plan)*
*	Local community support or opposition	*(provide latest comprehensive information)*
*	Community outreach efforts	*(provide latest comprehensive information)*
*	Community benefits	*(provide latest comprehensive information)*

2.9 OPERATIONS AND MAINTENANCE (O&M)

2.9.1 To demonstrate the long-term operational viability of the proposed Project, describe the **planned operations and maintenance**, including:

- Operations and maintenance funding levels, annually, throughout the term of the contract.
- Description of the operational requirements by frequency (daily, weekly, monthly, yearly, as-necessary, run hour interval) and maintenance requirements by frequency (daily, weekly, monthly, yearly, as-necessary, run hour interval).
- A discussion of the staffing levels proposed for the Project and location of such staff. If such staff is offsite, describe response time and ability to control the Project remotely.
- Technology specific maintenance experience records.
- Identification of any O&M providers.
- The expected role of the Proposer (Owner) or outside contractor.
- Scheduling of major maintenance activity.
- Plan for testing equipment.
- Estimated life of Generation and/or Storage Facilities and associated Interconnection Facilities.
- Safety plan, including historical safety records with environmental history records, violations, and compliance plans.
- Security plan.
- Site maintenance plan.
- Substation equipment maintenance plan.

2.9.2 State whether the Proposer would **consider 24-hour staffing**. Explain how this would be done.

2.9.3 Describe the **Proposer's contingency plan**, including the Proposer's mitigation plans to address failures. Such information should be described in the Proposal to demonstrate the Project's reliability with regard to potential operational issues.

2.9.4 Describe if the Proposer will **coordinate their maintenance schedule** for the Project with the Company's annual planned generation maintenance. See Article 5 of the Model Stage 3 Contract.

2.9.5 Describe the **status of any O&M agreements or contracts** that the Proposer is required to secure. Include a discussion of the Proposer's plan for securing a long-term O&M contract.

2.9.6 Provide **examples of the Proposer's experience with O&M services** for other similar projects.

2.10 PERFORMANCE STANDARDS

2.10.1 Design and operating information. Provide a **description of the project design**. Description shall include:

- Configuration description, including conceptual or schematic diagrams
- Overview of the Facility Control Systems – central control and inverter- or resource-level control
- Diagrams approved by a Professional Electrical Engineer registered in the State of Hawai‘i, indicated by the presence of the Engineer’s Professional seal on all drawings and documents. Including but not limited to:
    - A single-line diagram, relay list, trip scheme and settings of the generating facility, which identifies the Point of Interconnection, circuit breakers, relays, switches, synchronizing equipment, monitoring equipment, and control and protective devices and schemes.
    - A three-line diagram which shows the Point of Interconnection, potential transformer (PT) and current transformer (CT) ratios, and details of the generating facility configuration, including relays, meters and test switches.

2.10.1.1 For Generation Facilities, provide the projected **hourly annual energy potential production profile of the Facility**[14] **(24 hours x 365 days, 8760 generation profile)** for the provided RFP NEP Projection.

2.10.1.2 Provide the **sample rate of critical telemetry** (i.e. frequency and voltage) based on inputs to the facility control systems.

2.10.1.3 Provide a description of the Facility’s **capability to be grid-forming and have black start capability**.

2.10.1.4 Provide the explanation of the methodology and underlying **information used to derive the Project’s NEP RFP Projection**, including the preliminary design of the Facility and the typical meteorological year file used to estimate the Renewable Resource Baseline, as required in Article 6.6 of the applicable model Stage 3 Contract. The explanation of the methodology should include, but not be limited to, the long-term resource data used, the gross and net generation MWh, and assumptions (loss factors, uncertainty values, any grid or project constraints).

2.10.2 **Capability of Meeting Performance Standards**. The proposed Facility must meet the performance attributes identified in this RFP and the Performance Standards identified in the applicable Stage 3 Contract. Provide **confirmation that the proposed Facility will meet the requirements identified in the model Stage 3 Contract** or provide clarification or comments about the Facility’s ability to meet the performance standards. Proposals should include sufficient documentation to support the stated claim that the Facility will be able to meet the Performance Standards. The Proposal should include information required to make such a determination in an organized manner to ensure this evaluation can be completed within the evaluation review period.

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[14] The projected hourly annual energy production profile is the projected output from the generating facility without curtailment and before any energy is directed to an energy storage component, if one will be provided.

2.10.3 **Reactive Power Control**: Provide the facility's ability to meet the Reactive Power Control capabilities, including Voltage Regulation at the point of interconnection, required in the Performance Standards, including contribution from the inverters of generation and/or storage and means of coordinating the response. Provide the inverter capability curve(s). Confirm ability to provide reactive power at zero active power.

2.10.4 **Ramp Rate** for Generation Facilities: Confirm the ability to meet the ramp rate requirement specified in the Model Stage 3 Contract.

2.10.5 **Undervoltage ride-through**: Provide the facility’s terminal voltage level(s) and elapsed time at which the facility will disconnect from the utility system during the disturbance, if any. Confirm the ability to meet ride-through requirements and include supporting documentation regarding inverter design, control parameters, etc.

2.10.6 **Overvoltage ride-through**: Provide the facility’s terminal voltage level(s) and elapsed time at which the facility will disconnect from the utility system during the disturbance, if any. Confirm the ability to meet ride-through requirements and include supporting documentation regarding inverter design, control parameters, etc.

2.10.7 **Transient stability ride-through**: Provide the facility's ability to stay online during Company System: (1) three-phase fault located anywhere on the Company System and lasting up to__ cycles; and (2) a single line to ground fault located anywhere on the Company System and lasting up to__ cycles. Provide the Facility’s ability to withstand subsequent events.

2.10.8 **Short-Term Over-Current**: Provide the facility’s short-term over-current capability to supply inrush currents during energizing of transformers and distribution feeders and starting auxiliary motors of conventional power plants.

2.10.9 **Underfrequency ride-through**: Provide the facility’s terminal frequency level(s) and elapsed time at which the facility will disconnect from the utility system during the disturbance, if any. Confirm the ability to meet ride-through requirements and include supporting documentation regarding inverter design, control parameters, etc.

2.10.10 **Overfrequency ride-through**: Provide the facility’s terminal frequency level(s) and elapsed time at which the facility will disconnect from the utility system during the disturbance, if any. Confirm the ability to meet ride-through requirements and include supporting documentation regarding inverter design, control parameters, etc.

2.10.11 **Frequency Response**: Provide the facility’s frequency response characteristics as required by the model Stage 3 Contract, including time of response, tunable parameters, alternate frequency response modes and means of implementing such features.

2.10.12 **Auxiliary Power Information**: Proposer must provide the maximum auxiliary power requirements for:

- Start-up
- Normal Operations (from generator)
- Normal Operating Shutdown

- Forced Emergency Shutdown
- Maintenance Outage

2.10.13 **Coordination of Operations**: Provide a description of the control facilities required to coordinate generator operation with and between the Company's System Operator and the Company's System.

- Include a description of the equipment and technology used to facilitate dispatch to the Company and communicate with the Company.
- Include a description of the control and protection requirements of the generator and the Company's System.

2.10.14 **Cycling Capability**: Describe the Facility's ability to cycle on/off and provide limitations.

2.10.15 **Active Power Control Interface**: Describe the means of implementing active power control and the Power Possible, including the contribution to the dispatch signal from paired storage, if any. Provide the Proposer's **experience** dealing with active power control, dispatch, frequency response, and ride-through.

2.10.16 Provide the details of the **major equipment** (e.g., batteries, inverters, battery management system), including, but not limited to, name of manufacturer, models, key metrics, characteristics of the equipment, and performance specifications.

2.10.17 **Energy Storage performance standards**: For stand-alone storage projects or generation projects that include a storage component, provide additional performance standard descriptions as follows:

- MWh storage output for a full year
- Ramp Rate: Provide the Facility's ramp rate, which should be no more than 2 MW/minute for all conditions other than those under control of the Company System Operator and/or those due to desired frequency response.
- System Response Time – Idle to Design Maximum (minutes)
- Discharge Start-up time (minutes from notification)
- Charge Start-up time (minutes from notification)
- Start and run-time limitations, if any
- Ancillary Services provided, if any (i.e. Spinning Reserves, Non-Spinning Reserves, Regulation Up, Regulation Down, Black Start capability, other)

2.10.18 Provide the description and details of the **grid-charging capabilities of the Facility**. Include a description on the ability to control the charging source.

2.11 INTERCONNECTION REQUIREMENT STUDY

2.11.1 Provide the appropriate completed **Project Interconnection Data Request worksheets** for the proposed technology with the Proposal submission. (The worksheets can be found in the Electronic Procurement Platform's "1. Download Documents" tab as S3 HI Appx B - Att 2a Data Request (PV_BESS) 2021-09-13.xls, S3 HI Appx B - Att 2b Data Request (Wind) 2020-08-28.xls or S3 HI Appx B - Att 2c Data Request (Sync Gen) 2021-03-17.xls MSExcel files.) Standalone Storage Projects will use the S3 HI Appx B - Att 2a Data Request (PV_BESS) 2021-09-13.xls worksheet and omit the PV sections.

2.11.2 Also provide all **project single line and three line diagram(s)** with the Proposal submission**.**

2.11.3 **Models for equipment and controls** (see Appendix B Attachment 4)**, complete documentation and user manuals for all technical models** (for inverters and power plant controller)**, generation unit manufacturer datasheet(s), generation unit reactive power capability curve(s), overlaid generation facility technical model output data for three-phase fault and single-phase fault,** and a **report, with plots, documenting that Proposers have tested their models under all scenarios prescribed** shall be submitted within the timeframes specified in Section 5.1 of the RFP. Proposers may also download the **Facility Technical Model Requirements and Review Process** documentation labelled as S3 HI Appx B - Att 3 IRS Model Req Review Process.pdf from the "1. Download Documents" tab.

2.11.4 See Appendix B Attachment 4 for a summary of the model requirements and IRS task scope.

2.12 PROVEN TECHNOLOGY

2.12.1 Provide all supporting information for the Company to assess the **commercial and financial maturity of the technology** being proposed. Provide any supporting documentation that shows examples of projects that:

- Use the technology at the scale being proposed
- Have successfully reached commercial operations (for example, by submitting a PPA)
- Demonstrate experience in providing Active Power dispatch

2.13 EXPERIENCE AND QUALIFICATIONS

Proposers, its affiliated companies, partners, and/or contractors and consultants are required to demonstrate project experience and management capability to successfully develop and operate the proposed Project.

2.13.1 Provide a hierarchical **organizational/management chart** for the Project that lists all key personnel and project participants dedicated to the Project and identifies the management structure and responsibilities. In addition to the chart, Proposers must provide biographies/resumes of the key personnel, including position, years of relevant experience and similar project experience. Proposers must provide specifics on each participants' area of expertise in renewable energy projects. Identify architects and engineers or provision to provide same that are licensed to practice in the State of Hawai'i. Proposers must also provide a completed table:

- For each of the project participants (including the Proposer, partners, and proposed contractors), **fill out the table below** and provide statements that list the specific experience of the individual in: financing, designing, constructing, interconnecting, owning, operating, and maintaining renewable energy generating or storage facilities, or other projects of similar size and technology, and
- Provide any evidence that the project participants have worked jointly on other projects.

	EXPERIENCE: In the applicable columns below, include project details (i.e., project name, location, technology, size) and relevant job duties (role/responsibilities) and time (in years/months) spent on the project. List multiple projects if applicable.

Participant Name:	Financing	Designing	Constructing	Interconnecting	Owning	Operating	Maintaining
1.							
2.							
3.							
…							

2.13.2 Identify those **members of the team** the Proposer is submitting in the Experience Table above to meet the experience and qualifications requirement, included in the Threshold Requirement. Identify those **members of the team with the experience and qualifications,** including affiliates, and their principal personnel who will be involved in the project. If the Proposer consists of multiple parties, such as joint ventures or partnerships, demonstrate each member(s) firm commitment to provide services to the project (e.g., letter of intent); provide this information for each party, clearly indicating the proposed role of each party, including an ownership chart indicating direct and indirect ownership, and percentage interests in the partnership or joint venture.

2.13.3 Provide a **listing in the table format below, of all renewable energy generation or energy storage projects** the Proposer has successfully developed or that are currently under construction. Describe the Proposer's role and responsibilities associated with these projects (lead developer, owner, investor, etc.). Provide the following information as part of the response:

Project Name	Location (City, State)	Technology (wind, PV, hydro, plus storage, etc.)	Size (MW/ MWh)	Commercial Operation Date	Offtaker (if applicable)	Role & Responsibilities
1.						
2.						
3.						
…						

2.14 STATE OF PROJECT DEVELOPMENT AND SCHEDULE

2.14.1 Provide a **project schedule in GANTT chart format** with complete **critical path activities** identified for the Proposal from the Notice of Selection of the Proposal to the start of Commercial Operations.

- The **schedule** must include:
  - Interconnection Requirement Study (IRS) assumptions
  - Anticipated contract negotiation period assumptions
  - Regulatory assumptions
  - Anticipated submittal and approval dates for permitting (including but not limited to environmental and archaeological compliance)
  - Siting and land acquisition
  - Cultural Resource implications and mitigation activities
  - Community outreach and engagement activities
  - Energy resource assessment
  - Financing

- Engineering
- Procurement
- Facility construction including construction management events
- Applicable reporting milestone events specified in the Model Stage 3 Contract
- Testing
- Interconnection (including engineering, procurement, and construction)
- Commercial Operations Date
- All other important elements outside of the direct construction of the Project

- The project schedule must be created in Microsoft Project and submitted in a .mpp file format.
- For each project element, list the start and end date (must be in MM/DD/YY format), and include predecessors to clearly illustrate schedule dependencies and durations.
- Proposers must also list and describe critical path activities and milestone events, particularly as they relate to the integration and coordination of the project components and the Company's Electric System. Proposers must ensure that the schedule provided in this section is consistent with the milestone events contained in the Stage 3 Contract and/or other agreements.

2.14.2 Describe the **construction execution strategy** including:

- Identification of contracting/subcontracting plans
- Modular construction
- Safety plans[15]
- Quality control and assurance plan
- Labor availability
- Likely manufacturing sites and procurement plans
- Similar projects where these construction methods have been used by the Proposer

2.14.3 Provide a description of any **project activities that have been performed to date**.

2.14.4 Explain how you plan to reach **safe harbor milestones** (if applicable) and **guaranteed commercial operations**, including durations and dependencies which support this achievement.

2.15 CARBON EMISSION QUESTIONNAIRE

2.15.1 Answer the following Carbon Criteria questions. To mitigate the possibility of providing responses to questions that are optimistic or would result in a better score for the Carbon Criteria questions, please provide conservative answers where answers are unknown or uncertain. Guidance for providing conservative answers has been provided for each question. If a question or Category's questions are not applicable to the Project, please leave blank. For instance, if the Project generation technology does not include solar, leave questions in Category "3e. Procurement – Solar" blank.

Category	**#**	**Question**	***Answer Choices***

[15] A document that describes the various safety procedures and practices that will be implemented on the Project and how applicable safety regulations, standards, and work practices will be enforced on the Project.

1. Siting	1	Please provide the Project's expected annual production capacity per developed Site area in units of MWh/yr/m^2. *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected annual production capacity per developed Site area in units of MWh/yr/m^2.*	*Numerical write in*
	2	What is the expected distance from the Project's generation/storage location to the point of interconnection? *If the answer to this question is unknown or if there are multiple possibilities, please conservatively provide the furthest expected distance from the Project's generation/storage location to the point of interconnection*	*Numerical write in*
	3	What fraction of the Project's Site is a "greenfield", e.g. has not been previously developed? *If the answer to this question is unknown or uncertain, please conservatively provide the maximum expected "greenfield" fraction.*	*Numerical write in*
	4	What fraction of the Project's Site requires grading? *If the answer to this question is unknown or uncertain, please conservatively provide the maximum expected fraction.*	*Numerical write in*
	5	What is the expected fraction (in terms of CAPEX) of infrastructure being reused (includes roads, buildings, trenches, pads) for the Project? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected fraction.*	*Numerical write in*
2. Procurement	6	What fraction of concrete, fencing, gravel and other roadway materials used for the Project will be locally sourced on island? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected fraction.*	*Numerical write in*
	7	If available, please provide manufacturer-specific carbon footprint for major components and feedstock, along with supporting documentation. For power generating components, such as solar panels/wind turbines/biomass combustor, please provide the carbon footprint in units of kg CO_2e/kWh. For carbon feedstock, please provide in units of kg CO_2e/MMBtu energy content. *If this information is unavailable, please answer "Not available at this time".*	*Numerical write-in and supporting documentation*
	8	What fraction of roadway materials and gravel used for the Project will be made from recycled materials? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected fraction.*	*Numerical write in*

3a. Procurement – Biofuels ***please answer only if the project includes biofuels-based generation***	9	What fraction of the biofuel feedstock used for the Project is also a food or animal feedstock? *If the answer to this question is unknown or uncertain, please conservatively provide the maximum expected fraction.*	*Numerical write in*
	10	What fraction of the biofuel feedstock used for the Project is a waste product? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected fraction.*	*Numerical write in*
	11	What fraction of the harvested biofuel feedstock used for the Project will be replaced and regrown within one year of harvesting? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum fraction.*	*Numerical write in*
	12	How much hydrogen will be used in the biofuel production process for hydroprocessing (kg hydrogen/kg biofuel produced)? *If the answer to this question is unknown or uncertain, please conservatively provide the maximum expected amount in units of kg hydrogen/kg biofuel produced.*	*Numerical write in*
	13	How much fossil fuel energy will be consumed per electricity generated by the Project (kg fossil fuel/kWh)? *If the answer to this question is unknown or uncertain, please conservatively provide the maximum expected amount in units of kg fossil fuel/kWh.*	*Numerical write in*
3b. Procurement – Biomass ***please answer only if the project includes biomass-based generation***	14	What is the expected overall efficiency of the Project's biomass conversion to electricity (electricity generated by the Project divided by the energy in the biomass combusted)? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected overall efficiency.*	*Numerical write in*
	15	What is the expected biomass combustion efficiency of the biomass used for the Project (actual heat produced by combustion divided by the total heat potential of the biomass combusted)? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected biomass combustion efficiency.*	*Numerical write in*
	16	What fraction of the harvested biomass feedstock used for the Project will be replaced and regrown within one year of harvesting? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum fraction.*	*Numerical write in*

3c. Procurement – Energy Storage ***please answer only if the project includes energy storage***	17	What is the expected return efficiency of the Project's energy storage system (MWh returned to the grid/MWh stored)? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected return efficiency.*	*Numerical write in*
	18	How many cycles will the batteries used for the Project's energy storage system undergo annually? *If the answer to this question is unknown or uncertain, please conservatively provide the maximum expected number of cycles.*	*Numerical write in*
	19	What is the expected battery lifetime before degradation of the Project's energy storage efficiency below 80%? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected lifetime.*	*Numerical write in*
3d. Procurement – Geothermal ***please answer only if the project includes geothermal generation***	20	Will the Project's geothermal process be an enhanced geothermal system (EGS), flash/dry steam, or binary steam power plant? *If the answer to this question is unknown or uncertain, please conservatively answer "Not known at this time".*	*Text write in*
	21	Will the Project's geothermal process be closed loop? *If the answer to this question is unknown or uncertain, please conservatively answer "No".*	*Yes / No*
	22	What percentage of mass of fluid will be cascaded compared to total extracted fluid mass? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected percentage.*	*Numerical write in*
	23	Will new geothermal wells need to be drilled for the Project? *If the answer to this question is unknown or uncertain, please conservatively answer "Yes".*	*Yes / No*
3e. Procurement – Solar ***please answer only if the project includes solar generation***	24	What is the expected solar irradiance for the Project (kW/m^2)? *If the answer to this question is unknown or uncertain, please conservatively answer "Not known at this time".*	*Numerical write in*
	25	Which type of solar panels will be installed for the Project? a. Cadmium Telluride b. Single Crystalline Silicon c. Multicrystalline Silicon d. Other, if yes, please provide details regarding solar panel technology type. *If the answer to this question is unknown or uncertain, please conservatively answer "Not known at this time".*	*Yes/No* *If "Other", include write-in*

	26	What is the solar conversion efficiency of the solar panels (solar kW/m^2 / kW/m^2 produced) used for the Project? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum solar conversion efficiency.*	*Numerical write in*
3f. Procurement – Waste-to-Energy ***please answer only if the project includes Waste-to-Energy generation***	27	What fraction of the waste feedstock used for the Project will be organic waste (food, waste paper, green (i.e. compostable) waste, etc.)? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected fraction.*	*Numerical write in*
	28	What fraction of the fleet used to transport the waste feedstock to the Facility will consume renewable diesel or be electric? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected fraction.*	*Numerical write in*
	29	If the Waste-to-Energy process used for the Project will emit greenhouse gases, what fraction of the greenhouse gases will be captured? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected fraction.*	*Yes / No If "Yes", include numerical write in*
	30	What is the expected overall electrical efficiency of the Project process (electricity produced divided by the energy utilized for the waste-to-energy process) (kWh produced/kWh utilized for processing)? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum overall electrical efficiency expected.*	*Numerical write in*
3g. Procurement – Wind ***please answer only if the project includes wind generation***	31	What fraction of the rotors used for the Project will be made from recycled materials? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected fraction.*	*Numerical write in*
	32	Please provide the expected wind energy availability for the Project's location as it is related to the available wind speed (MW). *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected wind energy availability.*	*Numerical write in*
	33	Please provide the expected power generation ratio of the Project. *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected power generation ratio.*	*Numerical write in*

	34	Please provide the expected power coefficient of the Project. *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected power coefficient of the Project.*	*Numerical write in*
	35	What percentage by weight of the turbine tower will be steel? *If the answer to this question is unknown or uncertain, please conservatively provide the maximum expected percentage.*	*Numerical write in*
4. Construction	36	What fraction of the equipment used during the construction phase of the Project will consume renewable fuel? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected fraction.*	*Numerical write in*
	37	Will the Site have an anti-idle policy for the equipment used during the construction phase of the Project? *If the answer to this question is unknown or uncertain, please conservatively answer "No".*	*Yes / No*
	38	How many hours of helicopter use will be required for construction phase of the Project? *If the answer to this question is unknown or uncertain, please conservatively answer "Yes".*	*Numerical write in*
	39	What fraction of construction workers traveling to the Site during the construction phase of the Project will be local to Hawai'i? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum fraction of construction workers traveling to the Site during the construction phase of the Project may be local to Hawai'i.*	*Numerical write in*
5. Operations & Maintenance	40	What fraction of Project equipment and materials will need to be replaced during the Project's proposed Contract Term (e.g., Project lifetime) as a percentage of capital cost? *If the answer to this question is unknown or uncertain, please conservatively provide the maximum expected fraction of Project equipment and materials may need to be replaced during the Project's proposed Contract Term by using an above-average scenario for number of equipment failures and wear-and-tear on project materials.*	*Numerical write in*
	41	Will any equipment containing high global warming potential gases (such as sulfur hexafluoride (SF_6) or hydrofluorocarbons (HFCs)) be installed or used during operation? If yes, please provide the type of equipment and high global warming potential greenhouse gas and approximate quantity (kg) leaked per year.	*Yes / No* *If "Yes", include numerical write in*

		If the answer to this question is unknown or uncertain, please conservatively assume "Yes" and provide a maximum expected quantity(kg) leaked per year.	
	42	What is the expected electricity load from the grid over the Project's proposed Contract Term as a percentage of the Project's total electricity production? *If the answer to this question is unknown or uncertain, please conservatively provide the maximum electricity load from the grid as a percentage of the Project's total electricity production.*	*Numerical write in*
	43	What is the expected onsite electricity use over the Project's proposed Contract Term as a percentage of the Project's total electricity production? *If the answer to this question is unknown or uncertain, please conservatively provide the maximum expected onsite electricity use over the Project's proposed Contract Term as a percentage of the Project's total electricity production.*	*Numerical write in*
	44	What fraction of the equipment used for the Operations & Maintenance of the Project will consume renewable fuel or be electric? *If the answer to this question is unknown or uncertain, please conservatively provide the minimum expected fraction.*	*Numerical write in*
6. General	45	Please provide any additional information available likely to impact the Project's lifecycle (i.e., including raw materials and extraction, transportation, construction, operations & maintenance, and decommissioning & disposal) greenhouse gas emissions.	*Text write in*
	46	Please describe any additional actions that will be taken to reduce the Project's lifecycle greenhouse gas emissions, if not already captured in above responses. If no actions are intended at this time, please state that.	*Text write in*

(OPTIONAL) MINOR PROPOSAL VARIATIONS

Proposers submitting minor variations to their base variation (as allowed in RFP Section 1.8.2 and 1.8.3) must provide the **details of each variation in the below section(s)**. In the proposal variation section below, Proposers must (1) provide a completed Proposal Summary Table identical to Section 2.0 of this Appendix B in Section 3 and in Section 4 (if applicable). The information in these tables must reflect the information for the variation being proposed. Additionally, Proposers must (2) identify all changes to the information provided in response to Sections 2.2.4 through 2.14 of this Appendix B for the proposal variation. If differences from any section in Sections 2.2.4 through 2.14 are not identified, the Company will assume that the information contained in the base variation (Sections 2.2.4 through 2.14) also applies to the proposal variation.

Note: Section 2.2.2 above requires the inclusion of a table summarizing the differences among the variations, if variations are proposed.

(AS NECESSARY)

3.1 RESERVED

3.2 VARIATION A SUMMARY

3.3 VARIATION A FINANCIALS

3.4 VARIATION A CONTRACT EXCEPTIONS

3.5 VARIATION A SITE CONTROL

3.6 VARIATION A ENVIRONMENTAL COMPLIANCE AND PERMITTING PLAN

3.7 VARIATION A CULTURAL RESOURCE IMPACTS

3.8 VARIATION A COMMUNITY OUTREACH

3.9 VARIATION A O&M

3.10 VARIATION A PERFORMANCE STANDARDS

3.11 VARIATION A INTERCONNECTION SUBMITTAL REQUIREMENTS

3.12 VARIATION A PROVEN TECHNOLOGY

3.13 VARIATION A EXPERIENCE AND QUALIFICATIONS

3.14 VARIATION A STATE OF PROJECT DEVELOPMENT AND SCHEDULE

3.15 VARIATION A CARBON EMISSION QUESTIONNAIRE

(AS NECESSARY)

4.1 RESERVED

4.2 VARIATION B SUMMARY

4.3 VARIATION B FINANCIALS

4.4 VARIATION B CONTRACT EXCEPTIONS

4.5 VARIATION B SITE CONTROL

4.6 VARIATION B ENVIRONMENTAL COMPLIANCE AND PERMITTING PLAN

4.7 VARIATION B CULTURAL RESOURCE IMPACTS

4.8 VARIATION B COMMUNITY OUTREACH

4.9 VARIATION B O&M

4.10 VARIATION B PERFORMANCE STANDARDS

4.11 VARIATION B INTERCONNECTION SUBMITTAL REQUIREMENTS

4.12 VARIATION B PROVEN TECHNOLOGY

4.13 VARIATION B EXPERIENCE AND QUALIFICATIONS

4.14 VARIATION B STATE OF PROJECT DEVELOPMENT AND SCHEDULE

4.15 VARIATION B CARBON EMISSION QUESTIONNAIRE

Certification of Counsel for Proposer
Hawaiian Electric Company, Ltd.

Pursuant to Section 1.7.4 of Hawaiian Electric Company, Ltd.'s ("Company") Request For Proposals for Renewable Dispatchable Generation and Energy Storage ("RFP"), the Company may require legal counsel who represent multiple unaffiliated proposers to sign a certification that they have not shared confidential information obtained through the representation of one proposer with any other unafilliated proposer.

Accordingly, by signing below, I hereby acknowledge, agree and certify that:

(1) in connection with the RFP, I represent the following company that has submitted a proposal(s) for the RFP: ____________________ ("Proposer");

(2) irrespective of any proposer's direction, waiver or request to the contrary, I will not share a proposer's confidential information or the Company's confidential information associated with such proposer, including, but not limited to, a proposer's or Company's negotiating positions, with third parties unaffiliated with Proposer (by contract or organizational structure), including other proposers responding to the RFP;

(3) the Company may rely on this certification for purposes of the RFP; and

(4) at the conclusion of power purchase agreement negotiations, if any, the Company may require me to sign a certicate certifying that I have not shared a proposer's confidential information or the Company's confidential information associated with such proposer, including, but not limited to, a proposer's or Company's negotiating positions, with third parties unaffiliated with Proposer (by contract or organizational structure), including other proposers responding to the RFP.

____
Name (print)

____
Law Firm (if applicable)

______________________________ ______________________________
Signature Date

Section 1.7.4 of the RFP provides in relevant part that:

In submitting a Proposal in response to this RFP, each Proposer certifies that the Proposal has been submitted in good faith and without fraud or collusion with any other unaffiliated person or entity. The Proposer shall acknowledge this in the Response Package submitted with its Proposal. Furthermore, in executing the NDA provided as Appendix E, the Proposer agrees on behalf of its Representatives (as defined in the NDA) that the Company's negotiating positions will not be shared with other Proposers or their respective Representatives.

In addition, in submitting a Proposal, a Proposer will be required to provide Company with its legal counsel's written certification in the form attached as Appendix B, Attachment 1 certifying in relevant part, that irrespective of any Proposer's direction, waiver, or request to the contrary, the attorney will not share a Proposer's confidential information associated with such Proposer with others, including, but not limited to, such information such as a Proposer's or Company's negotiating positions. If legal counsel represents multiple unaffiliated Proposers whose Proposals are selected for the Final Award Group, such counsel will also be required to submit a similar certification at the conclusion of contract negotiations that he or she has not shared a Proposer's confidential information or the Company's confidential information associated with such Proposer with others, including but not limited to, such information as a Proposer's or Company's negotiating positions.

Project Interconnection - Data Request **Updated 9/13/2021**

FOR PV/BESS GENERATION

PROJECT:____

DATE: _____

(Nonexclusive Preliminary List)

*****ALL ITEMS ARE REQUIRED AND ALL RESPONSES MUST BE FILLED UNLESS NOT APPLICABLE.*****

		Response
1)	**Please provide a plan map of the Renewable Generation facility. Please indicate the interconnection point to the HECO system.**	
2)	**Please provide the following generation and load information for the Renewable Generation facility:**	
	a. Gross and net output of the facility	
	b. Expected KW and KVAR loads including, but not limited to, generators' auxiliary load curve, process load(s) profile(s), etc.	
	c. Expected minimum and maximum MW and MVAR “import from” AND “export to” HECO.	
3)	**Please provide Single-Line Diagram(s), Three-Line Diagram(s), and Protective Relay List & Trip Schedule for the generation and interconnection facilities:**	
	a. The Single-line diagram(s) and Three-line diagram (s) should include: i. For main and generator step up transformer(s), please show: • Transformer voltage and MVA ratings.	
	• Transformer impedance(s).	
	• Transformer winding connections and grounding. If neutrals are grounded through impedance, please show the impedance value.	
	ii. The protective relaying and metering for the generators, transformers, buses, and all other main substation equipment.	
	iii. For the potential transformers, please indicate the type, quantity, ratio, and accuracy rating.	
	iv. For the current transformers, please indicate the type, quantity, ratio, and accuracy rating, and thermal rating factor.	
	v. Auxiliary power devices (e.g. capacitors, reactors, storage systems, etc.) and their rating(s); additional inquiries may be made to obtain technical data for these devices.	
	vi. For the interconnection / tie lines (overhead or underground) and the plant's generation system, please provide the following, as applicable: • Installation details such as cross-section(s), plan and profiles, etc.	
	• Conductor data such as size, insulation, length etc.	
	• Continuous and emergency current ratings.	
	• Voltage rating (nominal and maximum KV).	
	• BIL rating.	
	• Positive, negative, and zero-sequence impedances (resistance, reactance, and susceptance)	
	• Capacitance or charging current.	
	• Short-circuit current capability.	
	vii. Include station power for facility and all applicable details.	
	viii. All applicable notes pertaining to the design and operation of the facility.	
	b. The Protective relay list & trip schedule should list the protected equipment; the relay description, type, style number, quantity, ANSI Device No., and range; and the breaker(s)/switching device(s) tripped, for both the generator protection and the interconnection facilities protection.	
	c. Please provide both a paper and an electronic version (e.g. dgn, dxf, or pdf) of the single-line diagram(s) and the protective relay list & trip schedule.	
	d. Single-line diagrams should be provided for both the generation plant and the interconnection substation.	

Project Interconnection - Data Request **Updated 9/13/2021**

FOR PV/BESS GENERATION

PROJECT:____

DATE: ______

(Nonexclusive Preliminary List)

*****ALL ITEMS ARE REQUIRED AND ALL RESPONSES MUST BE FILLED UNLESS NOT APPLICABLE.*****

		Response
4)	**For the PV Inverter Based Generating Faciltiy, please provide the following data, as applicable:**	
	a. Inverter manufacturer, Type, Size, Impedances. Attach copy of inverter data sheet.	
	b. Power Factor Range Capability	
	c. Inverter Reactive Power Capability Curve	
	d. Auxillary loads (P, Q, Power Factor)	
	e. Inverter's Internal Isolation Transformer Grounding Method, if used (i.e. effectively grounded, resonant grounded, low inductance grounded, high-resistance grounded, low-resistance grounded, ungrounded). If the transformer is not solidly grounded , provide the impedance value for the grounding neutral and the impedance for the isolation transformer.	
	f. Diagram for Inverter's internal isolation transformer	
	g. Switching and service restoration practice	
	h. Protection data (voltage ride-through and trip settings, frequency ride-through and trip settings etc.). Include setpoint and clearing time ranges for voltage and frequency settings.	
	i. Description of harmonic spectrum of inverter injection (order, magnitude)	
5)	**For the BESS Inverter Based Generating Faciltiy, please provide the following data (if system is DC coupled, please note DC coupling and reference to 4).**	
	a. Inverter manufacturer, Type, Size, Impedances. Attach copy of inverter data sheet.	
	b. Power Factor Range Capability	
	c. Inverter Reactive Power Capability Curve	
	d. Auxillary loads (P, Q, Power Factor)	
	e. Inverter's Internal Isolation Transformer Grounding Method, if used (i.e. effectively grounded, resonant grounded, low inductance grounded, high-resistance grounded, low-resistance grounded, ungrounded). If the transformer is not solidly grounded , provide the impedance value for the grounding neutral and the impedance for the isolation transformer.	
	f. Diagram for Inverter's internal isolation transformer	
	g. Switching and service restoration practice	
	h. Protection data (voltage ride-through and trip settings, frequency ride-through and trip settings etc.). Include setpoint and clearing time ranges for voltage and frequency settings.	
	i. Description of harmonic spectrum of inverter injection (order, magnitude)	
6)	**Energy Storage System, if applicable**	
	a. Operation characteristics	
	b. Voltage level	
	c. Capacity (how long and how much can the battery support)	
	d. Deployment strategy/schedule	
	e. Energy storage system data sheet	
7)	**For the PV plant's collector system, please provide the following, as applicable:**	
	a. Conductor data such as size, insulation, etc.	
	b. Continuous and emergency current ratings.	
	c. Voltage rating (nominal and maximum kV).	
	d. BIL rating.	
	e. Positive, negative, and zero-sequence impedances (resistance, reactance, and susceptance).	
	f. Capacitance or charging current.	

Project Interconnection - Data Request **Updated 9/13/2021**

FOR PV/BESS GENERATION

PROJECT:____

DATE: _____

(Nonexclusive Preliminary List)

*****ALL ITEMS ARE REQUIRED AND ALL RESPONSES MUST BE FILLED UNLESS NOT APPLICABLE.*****

	Response
g. Short-circuit current capability.	

8)

For the BESS plant's collector system, please provide the following, as applicable (if system is DC coupled, please note DC coupling and reference to 7):	
a. Conductor data such as size, insulation, etc.	
b. Continuous and emergency current ratings.	
c. Voltage rating (nominal and maximum kV).	
d. BIL rating.	
e. Positive, negative, and zero-sequence impedances (resistance, reactance, and susceptance).	
f. Capacitance or charging current.	
g. Short-circuit current capability.	

Project Interconnection - Data Request **Updated 9/13/2021**
FOR PV/BESS GENERATION
PROJECT:____
DATE: ______
(Nonexclusive Preliminary List)
*****ALL ITEMS ARE REQUIRED AND ALL RESPONSES MUST BE FILLED UNLESS NOT APPLICABLE.*****

		Response
9)	**Please provide the following software models that accurately represent the Facility, as applicable:** (For model requirements, refer to the HECO Facility Technical Model Requirements and Review Process)	
	a. Validated PSS/E load flow model up to the point of interconnection. The PSS/E model shall include the main transformer, collection system, generator step-up transformers, inverter systems, and any other components including capacitor banks, energy storage systems, DVAR, etc. An equivalent respresentation of the collection system, generator step-up transformers, and inverter systems is acceptable. Documentation on the model shall be provided.	
	b. Validated PSS/E dynamic model for the inverter; and other components including energy storage system, DVAR, etc. if applicable. The inverter model shall include the generator/converter, electrical controls, plant-level controller, and protection relays. Generic and Detailed models shall be provided. Documentation on the model(s) shall be provided, including the PSS/E dyre file with model parameters.	
	i. Generic models shall parameterize models available within the PSS/E standard model library.	
	ii. Detailed models shall be supplied by the vendor/manufacturer as user-written models. The uncompiled source code for the user-written model shall be provided to ensure compatability with future versions of PSS/E. In lieu of the uncompiled source code, a compiled object file and applicable library files shall be provided in PSS/E versions 33 AND 34 format. Updates of the object file compatible with future PSS/E versions must be provided as requested for the life of the project as written in the power purchase agreement. Documentation shall include the characteristics of the model, including block diagrams, values, names for all model parameters, and a list of all state variables.	
	c. Validated PSCAD model of the inverter; and other components including energy storage system, DVAR, auxiliary plant controllers, etc. if applicable. Documentation on the model(s) shall be provided. Refer to PSCAD Model Requirements Memo for model requirements.	
	d. Overlayed plots validating the performance of the three dynamic models for a three-phase fault. Plots shall include voltage, real and reactive power, real and reactive current.	
	e. Validated Aspen Oneliner short circuit model that accurately represents the facility (including energy storage system if applicable), and is valid for all faults conditions anywhere on the Utility system. Documentation on the model(s) shall be provided. (OTHERWISE SEE ADDITIONAL TABS FOR REQUIRED INFORMATION TO MODEL INVERTER AS A GENERATOR OR A VOLTAGE CONTROLLED CURRENT SOURCE)	

10)	**For the main transformer and generator step-up transformers, please provide:**	
	a. Transformer voltage and MVA ratings, and available taps. Attach copy of transformer test report or data sheet	
	b. The tap settings used.	
	c. The LTC Control Scheme.	
	d. Transformer winding connections and grounding used. If the transformer is not solidly grounded, provide the impedance value for the grounding method.	
	e. Positive, negative, and zero sequence impedance values.	

11)	**For the circuit breakers and fault-clearing switching devices, including the generator breakers, please provide:**	
	a. The voltage, continuous current and interrupting capability ratings.	
	b. The trip speed (time to open).	

Project Interconnection - Data Request **Updated 9/13/2021**
FOR PV/BESS GENERATION
PROJECT:____
DATE: ______
(Nonexclusive Preliminary List)
*****ALL ITEMS ARE REQUIRED AND ALL RESPONSES MUST BE FILLED UNLESS NOT APPLICABLE.*****

		Response
12)	**For the power fuses, please provide:**	
	a. The manufacturer, type, size, and interrupting capability.	
	b. The minimum melt and total clearing curves.	

13)	**For the protective relaying, please provide:**	
	a. Data for the CTs used with the relaying including the manufacturer, type of CT, accuracy class, and thermal rating factor.	
	b. Data for the PTs used with the relaying including the manufacturer, type of PT, voltage ratings, and quantity.	

Instructions:
Please fill in the data in the green blanks below
(Note: This does not include the internal isolation transformer, if used)

[1] Maximum rated output power = ________ kVA

[2] Impedances in **Per Unit** based on kVA from [1]

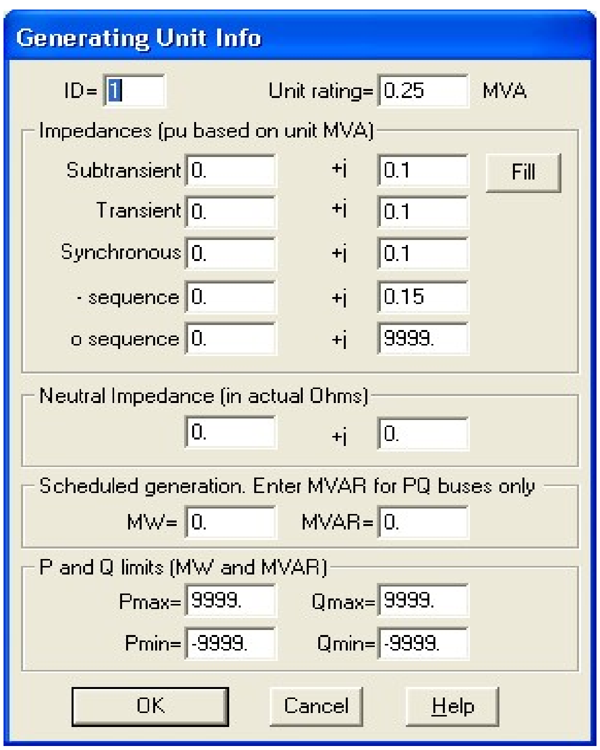
	R	X
Subtransient =		
Transient =		
Synchronous =		
Negative Sequence =		
Zero Sequence =		

[3] Neutral impedance (if any) in actual **Ohms**:

R	X

NOTE: These parameters should reflect the inverter response for all types of faults at any point on the electrical system to which the inverter is connected. This includes faults at the inverter output terminals, and also on the 138 kV transmission system. If the stated parameters do not cover this range, please state the adjustments needed to these parameters to accurately represent the inverter response across this range.

These parameters will be used to model the inverter in the Aspen Oneliner program as shown in the sample dialog box below:



Instructions:
Please fill in the data in the green blanks below

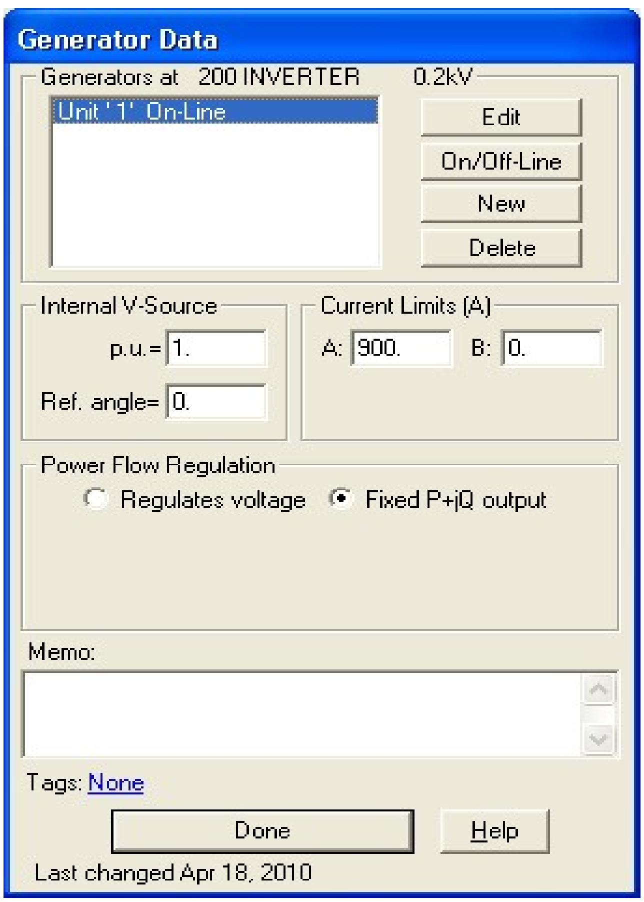
[1] Internal open circuit voltage

Magnitude =		Per Unit
Angle =		Degrees

[2] AC Output Current Limit = | | Amps

NOTE: These parameters should reflect the inverter response for all types of faults at any point on the electrical system to which the inverter is connected. This includes faults at the inverter output terminals, and also on the 138 kV transmission system. If the stated parameters do not cover this range, please state the adjustments needed to these parameters to accurately represent the inverter response across this range.

These parameters will be used to model the inverter in the Aspen Oneliner program as shown in the sample dialog box below:



Instructions:
Please fill in the data in the green blanks below

[1] Inverter MVA Rating: ________ MVA

[2] Voltage-Current Characteristics:

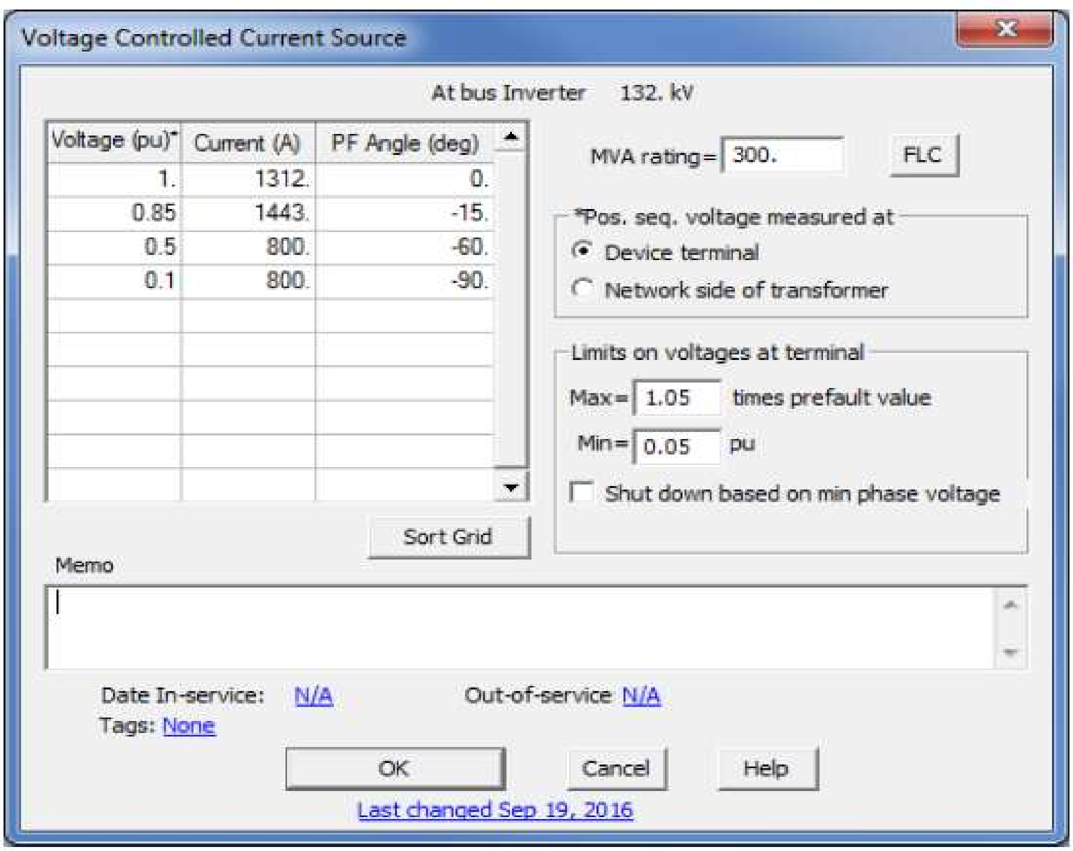
Voltage PU	Current (A)	PF Angle (deg)

[3] Location of Voltage Measurement: ________ Device Terminal OR ________ Network side of Transformer

[4] Maximum Voltage: ________ Times prefault value

[5] Minimum Voltage ________ Per Unit

These parameters will be used to model the inverter in the Aspen Oneliner program as shown in the sample dialog box below:



Instructions:
Please fill in the data in the green blanks below
(Note: This is not required if an internal isolation transformer is not used)

[1] Transformer rated power = kVA

[2] Winding Configuration
Inverter Side = Delta/Wye
Customer Side = Delta/Wye

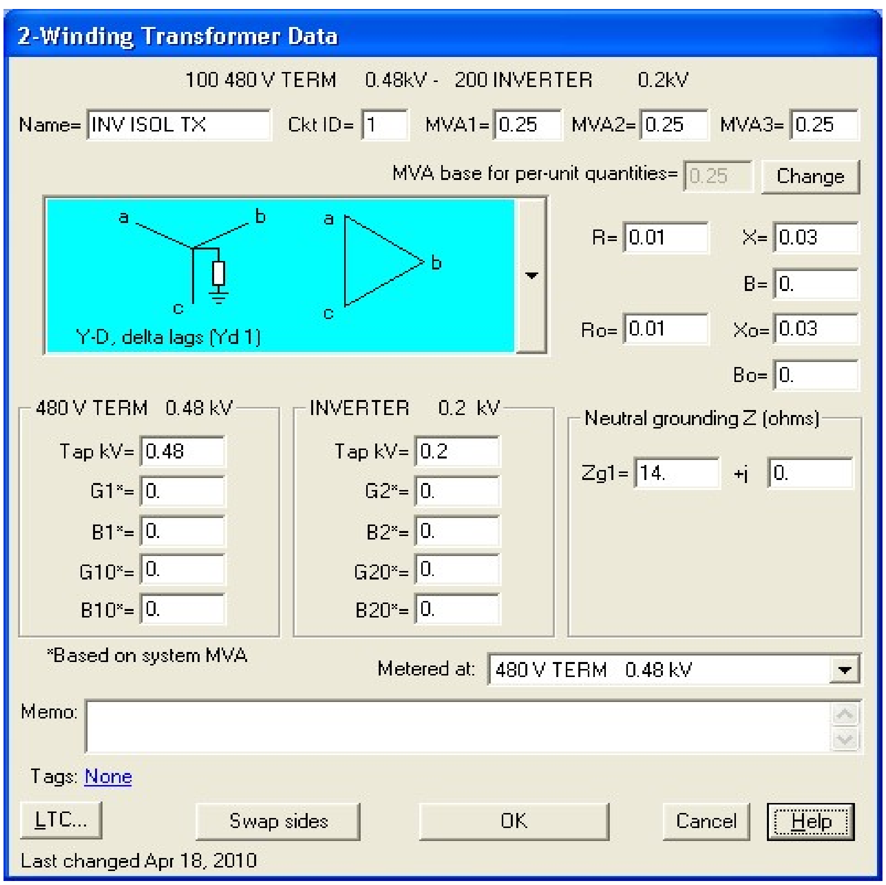
[2] Impedances in **Per Unit** based on kVA

	R	X
Positive Sequence =		
Zero Sequence =		

[3] Neutral impedance (if any) in actual **Ohms**:

R	X

These parameters will be used to model the inverter in the Aspen Oneliner program as shown in the sample dialog box below:



Project Interconnection - Data Request **Updated 8/28/2020**

FOR WIND GENERATION

PROJECT:____

DATE: _____

(Nonexclusive Preliminary List)

*****ALL ITEMS ARE REQUIRED AND ALL RESPONSES MUST BE FILLED UNLESS NOT APPLICABLE.*****

		Response
1)	**Please provide a plan map of the Non-Utility Generation (NUG) facility. Please indicate the interconnection point to the HECO system.**	

2)	**Please provide the following generation and load information for the NUG facility:**	
	a. Gross and net output of the facility	
	b. Expected KW and KVAR loads including, but not limited to, generators' auxiliary load curve, process load(s) profile(s), etc.	
	c. Expected minimum and maximum MW and MVAR “import from” AND “export to” HECO.	

3)	**Please provide Single-Line Diagram(s), Three-Line Diagram(s), and Protective Relay List & Trip Schedule for the generation and interconnection facilities:**	
	a. The Single-line diagram(s) and Three-line diagram (s) should include: i. For main and generator step up transformer(s), please show: • Transformer voltage and MVA ratings.	
	• Transformer impedance(s).	
	• Transformer winding connections and grounding. If neutrals are grounded through impedance, please show the impedance value.	
	ii. The protective relaying and metering for the generators, transformers, buses, and all other main substation equipment.	
	iii. For the potential transformers, please indicate the type, quantity, ratio, and accuracy rating.	
	iv. For the current transformers, please indicate the type, quantity, ratio, and accuracy rating, and thermal rating factor.	
	v. Auxiliary power devices (e.g. capacitors, reactors, storage systems, etc.) and their rating(s); additional inquiries may be made to obtain technical data for these devices.	
	vi. For the interconnection / tie lines (overhead or underground) and the plant's generation system, please provide the following, as applicable: • Installation details such as cross-section(s), plan and profiles, etc.	
	• Conductor data such as size, insulation, length etc.	
	• Continuous and emergency current ratings.	
	• Voltage rating (nominal and maximum KV).	
	• BIL rating.	
	• Positive, negative, and zero-sequence impedances (resistance, reactance, and susceptance)	
	• Capacitance or charging current.	
	• Short-circuit current capability.	
	vii. Include station power for facility and all applicable details.	
	viii. All applicable notes pertaining to the design and operation of the facility.	
	b. The Protective relay list & trip schedule should list the protected equipment; the relay description, type, style number, quantity, ANSI Device No., and range; and the breaker(s)/switching device(s) tripped, for both the generator protection and the interconnection facilities protection.	
	c. Please provide both a paper and an electronic version (e.g. dgn, dxf, or pdf) of the single-line diagram(s) and the protective relay list & trip schedule.	
	d. Single-line diagrams should be provided for both the generation plant and the interconnection substation.	

Project Interconnection - Data Request **Updated 8/28/2020**
FOR WIND GENERATION
PROJECT:____
DATE: ______
(Nonexclusive Preliminary List)
*****ALL ITEMS ARE REQUIRED AND ALL RESPONSES MUST BE FILLED UNLESS NOT APPLICABLE.*****

		Response
4)	**For the Wind Generating Faciltiy, please provide the following data:**	
	a. Turbine manufacturer, Type, Size, Impedances. Attach copy of turbine data sheet.	
	b. Power Factor Range Capability	
	c. Turbine Reactive Power Capability Curve	
	d. Auxillary loads (P, Q, Power Factor)	
	e. Grounding Method (i.e. effectively grounded, resonant grounded, low inductance grounded, high-resistance grounded, low-resistance grounded, ungrounded). If the transformer is not solidly grounded or ungrounded, provide the impedance value for the grounding neutral, if applicable.	
	f. Provide grounding diagram.	
	g. Switching and service restoration practice	
	h. Protection data (voltage ride-through and trip settings, frequency ride-through and trip settings etc.). Include setpoint and clearing time ranges for voltage and frequency settings.	
	k. Description of harmonic spectrum of inverter injection (order, magnitude)	

5)	**Energy Storage System, if applicable**	
	a. Operation characteristics	
	b. Voltage level	
	c. Capacity (how long and how much can the battery support)	
	d. Deployment strategy/schedule	
	e. Energy storage system data sheet	

6)	**For the Wind plant's collector system, please provide the following, as applicable:**	
	a. Conductor data such as size, insulation, etc.	
	b. Continuous and emergency current ratings.	
	c. Voltage rating (nominal and maximum kV).	
	d. BIL rating.	
	e. Positive, negative, and zero-sequence impedances (resistance, reactance, and susceptance).	
	f. Capacitance or charging current.	
	g. Short-circuit current capability.	

Project Interconnection - Data Request **Updated 8/28/2020**

FOR WIND GENERATION

PROJECT:____

DATE: _____

(Nonexclusive Preliminary List)

*****ALL ITEMS ARE REQUIRED AND ALL RESPONSES MUST BE FILLED UNLESS NOT APPLICABLE.*****

		Response
7)	**Please provide the following software models that accurately represent the Facility:** (For model requirements, refer to the HECO Facility Technical Model Requirements and Review Process and PSCAD Model Requirements Rev.9)	
	a. Validated PSS/E load flow model up to the point of interconnection. The PSS/E model shall include the main transformer, collection system, generator step-up transformers, wind turbines, and any other components including capacitor banks, energy storage systems, DVAR, etc. An equivalent respresentation of the collection system, generator step-up transformers, and turbines is acceptable. Documentation on the model shall be provided.	
	b. Validated PSS/E dynamic model for the wind turbine; and other components including energy storage system, DVAR, etc. if applicable. The wind turbine model shall include the generator/converter, electrical controls, plant-level controller, protection relays, and mechanical systems that impact its electrical performance. Generic and Detailed models shall be provided. Documentation on the model(s) shall be provided, including the PSS/E dyre file with model parameters.	
	i. Generic models shall parameterize models available within the PSS/E standard model library.	
	ii. Detailed models shall be supplied by the vendor/manufacturer as user-written models. The uncompiled source code for the user-written model shall be provided to ensure compatability with future versions of PSS/E. In lieu of the uncompiled source code, a compiled object file and applicable library files shall be provided in PSS/E versions 33 AND 34 format. Updates of the object file compatible with future PSS/E versions must be provided as requested for the life of the project as written in the power purchase agreement. Documentation shall include the characteristics of the model, including block diagrams, values, names for all model parameters, and a list of all state variables.	
	c. Validated PSCAD model of the wind turbine; and other components including energy storage system, DVAR, etc, if applicable. Documentation on the model(s) shall be provided. Refer to PSCAD Technical Memo for model requirements.	
	d. Overlayed plots validating the performance of the three dynamic models for a three-phase fault. Plots shall include voltage, real and reactive power, real and reactive current.	
	e. Validated Aspen Oneliner short circuit model that accurately represents the facility (including energy storage system if applicable), and is valid for all faults conditions anywhere on the Utility system. Documentation on the model(s) shall be provided. (OTHERWISE SEE ADDITIONAL TABS FOR REQUIRED INFORMATION TO MODEL INVERTER)	

8)	**For the main transformer and generator step-up transformers, please provide:**	
	a. Transformer voltage and MVA ratings, and available taps. Attach copy of transformer test report or data sheet	
	b. The tap settings used.	
	c. The LTC Control Scheme.	
	d. Transformer winding connections and grounding used. If the transformer is not solidly grounded, provide the impedance value for the grounding method.	
	e. Positive, negative, and zero sequence impedance values.	

9)	**For the circuit breakers and fault-clearing switching devices, including the generator breakers, please provide:**	
	a. The voltage, continuous current and interrupting capability ratings.	
	b. The trip speed (time to open).	

Project Interconnection - Data Request **Updated 8/28/2020**
FOR WIND GENERATION
PROJECT:____
DATE: ______
(Nonexclusive Preliminary List)
*****ALL ITEMS ARE REQUIRED AND ALL RESPONSES MUST BE FILLED UNLESS NOT APPLICABLE.*****

		Response
10)	**For the power fuses, please provide:**	
	a. The manufacturer, type, size, and interrupting capability.	
	b. The minimum melt and total clearing curves.	
11)	**For the protective relaying, please provide:**	
	a. Data for the CTs used with the relaying including the manufacturer, type of CT, accuracy class, and thermal rating factor.	
	b. Data for the PTs used with the relaying including the manufacturer, type of PT, voltage ratings, and quantity.	

Updated 8/28/20

Instructions:

Please fill in the data in the green blanks below

(Note: This does not include the internal isolation transformer, if used)

[1] Maximum rated output power = ______ kVA

[2] Impedances in **Per Unit** based on kVA from [1]

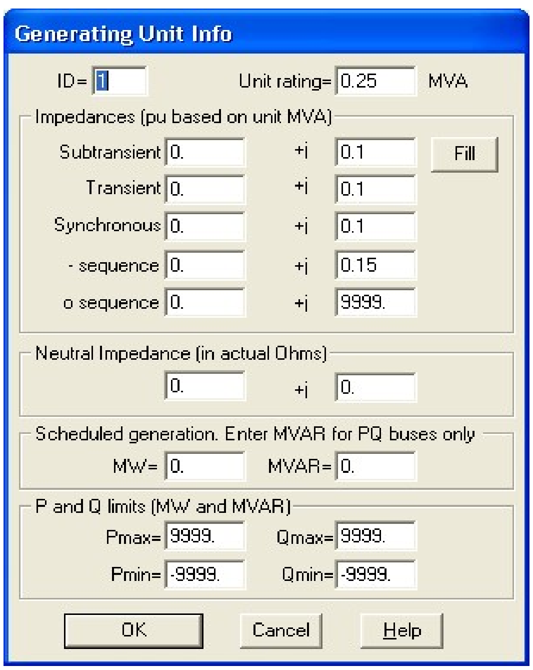
	R	X
Subtransient =		
Transient =		
Synchronous =		
Negative Sequence =		
Zero Sequence =		

[3] Neutral impedance (if any) in actual **Ohms**:

R	X

NOTE: These parameters should reflect the inverter response for all types of faults at any point on the electrical system to which the inverter is connected. This includes faults at the inverter output terminals, and also on the 138 kV transmission system. If the stated parameters do not cover this range, please state the adjustments needed to these parameters to accurately represent the inverter response across this range.

These parameters will be used to model the inverter in the Aspen Oneliner program as shown in the sample dialog box below:



Instructions:
Please fill in the data in the green blanks below

Updated 8/28/20

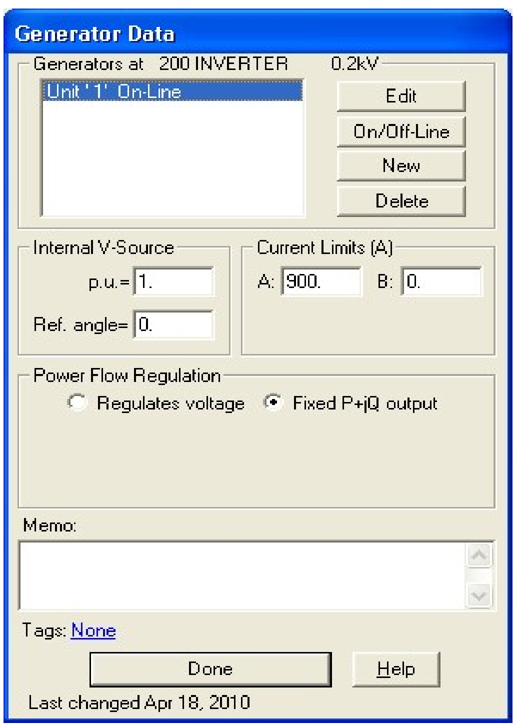
[1] Internal open circuit voltage

Magnitude = ______ Per Unit
Angle = ______ Degrees

[2] AC Output Current Limit = ______ Amps

NOTE: These parameters should reflect the inverter response for all types of faults at any point on the electrical system to which the inverter is connected. This includes faults at the inverter output terminals, and also on the 138 kV transmission system. If the stated parameters do not cover this range, please state the adjustments needed to these parameters to accurately represent the inverter response across this range.

These parameters will be used to model the inverter in the Aspen Oneliner program as shown in the sample dialog box below:



Instructions:
Please fill in the data in the green blanks below

Updated 8/28/20

[1] Inverter MVA Rating: ______ MVA

[2] Voltage-Current Characteristics:

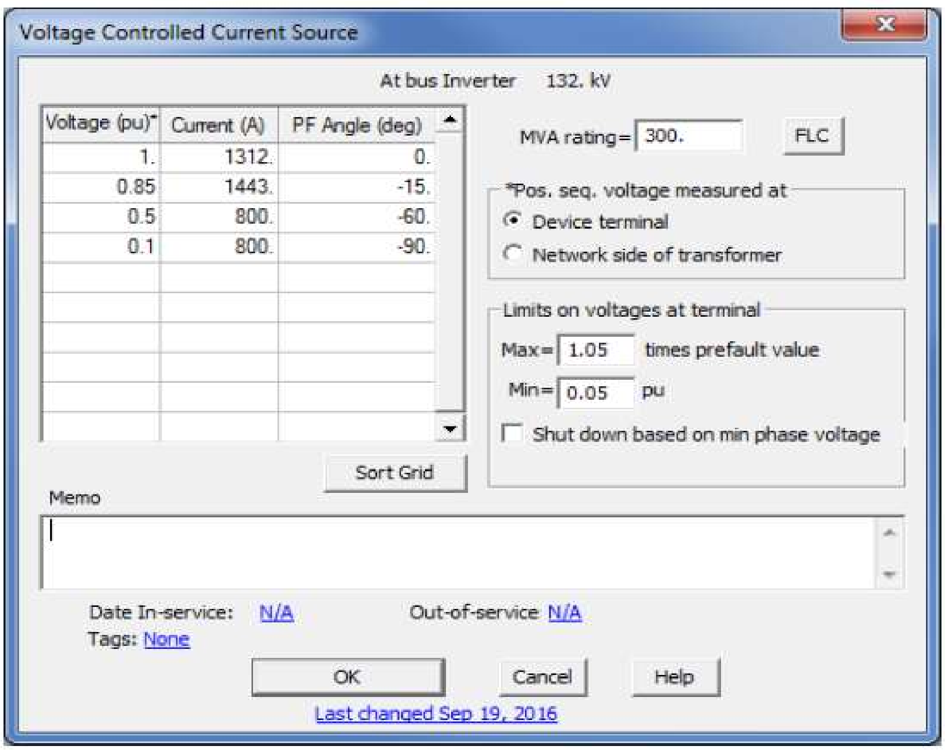
Voltage PU	Current (A)	PF Angle (deg)

[3] Location of Voltage Measurement: ______ Device Terminal OR ______ Network side of Transformer

[4] Maximum Voltage: ______ Times prefault value

[5] Minimum Voltage ______ Per Unit

These parameters will be used to model the inverter in the Aspen Oneliner program as shown in the sample dialog box below:



Updated 8/28/20

Instructions:
Please fill in the data in the green blanks below
(Note: This is not required if an internal isolation transformer is not used)

[1] Transformer rated power = ______ kVA

[2] Winding Configuration

Inverter Side =		Delta/Wye
Customer Side =		Delta/Wye

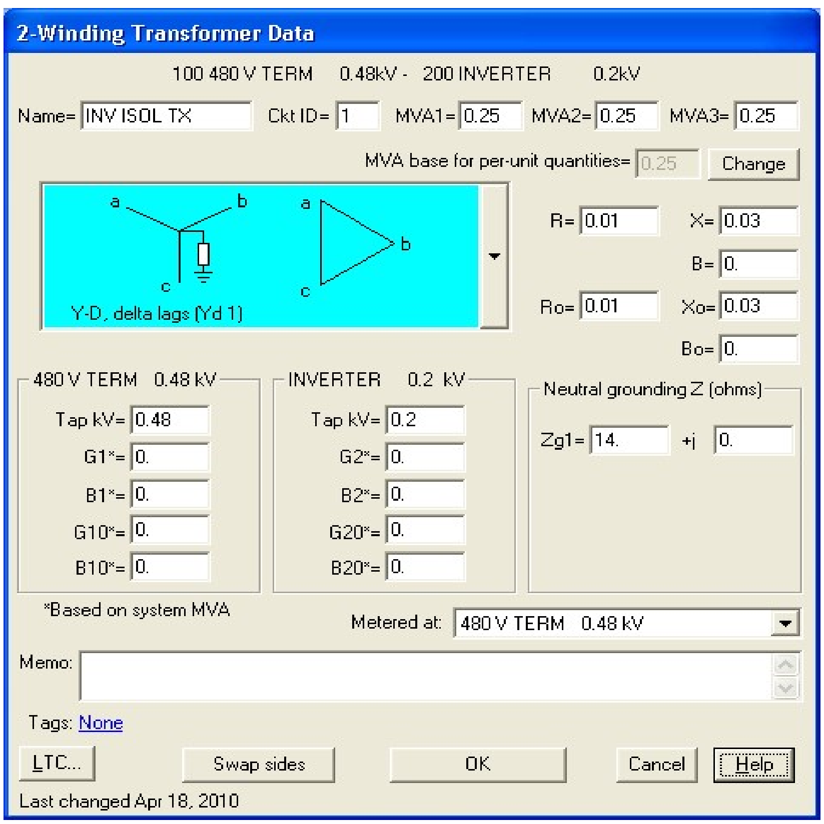
[2] Impedances in **Per Unit** based on kVA

	R	X
Positive Sequence =		
Zero Sequence =		

[3] Neutral impedance (if any) in actual **Ohms**:

R	X

These parameters will be used to model the inverter in the Aspen Oneliner program as shown in the sample dialog box below:



Project Interconnection - Data Request **Updated 3/17/2021**

FOR SYNCHRONOUS GENERATION

PROJECT:____

DATE: _____

(Nonexclusive Preliminary List)

*****ALL ITEMS ARE REQUIRED AND ALL RESPONSES MUST BE FILLED UNLESS NOT APPLICABLE.*****

		Response
1)	**Please provide a plan map of the Non-Utility Generation (NUG) facility. Please indicate the interconnection point to the HECO system.**	

2)	**Please provide the following generation and load information for the NUG facility:**	
	a. Gross and net output of the facility	
	b. Expected KW and KVAR loads including, but not limited to, generators' auxiliary load curve, process load(s) profile(s), etc.	
	c. Expected minimum and maximum MW and MVAR “import from” AND “export to” HECO.	

3)	**Please provide Single-Line Diagram(s), Three-Line Diagram(s), and Protective Relay List & Trip Schedule for the generation and interconnection facilities:**	
	a. The Single-line diagram(s) and Three-line diagram (s) should include: i. For main and generator step up transformer(s), please show: • Transformer voltage and MVA ratings.	
	• Transformer impedance(s).	
	• Transformer winding connections and grounding. If neutrals are grounded through impedance, please show the impedance value.	
	ii. The protective relaying and metering for the generators, transformers, buses, and all other main substation equipment.	
	iii. For the potential transformers, please indicate the type, quantity, ratio, and accuracy rating.	
	iv. For the current transformers, please indicate the type, quantity, ratio, and accuracy rating, and thermal rating factor.	
	v. Auxiliary power devices (e.g. capacitors, reactors, storage systems, etc.) and their rating(s); additional inquiries may be made to obtain technical data for these devices.	
	vi. For the interconnection / tie lines (overhead or underground) and the plant's generation system, please provide the following, as applicable: • Installation details such as cross-section(s), plan and profiles, etc.	
	• Conductor data such as size, insulation, length etc.	
	• Continuous and emergency current ratings.	
	• Voltage rating (nominal and maximum KV).	
	• BIL rating.	
	• Positive, negative, and zero-sequence impedances (resistance, reactance, and susceptance)	
	• Capacitance or charging current.	
	• Short-circuit current capability.	
	vii. Include station power for facility and all applicable details.	
	viii. All applicable notes pertaining to the design and operation of the facility.	
	b. The Protective relay list & trip schedule should list the protected equipment; the relay description, type, style number, quantity, ANSI Device No., and range; and the breaker(s)/switching device(s) tripped, for both the generator protection and the interconnection facilities protection.	
	c. Please provide both a paper and an electronic version (e.g. dgn, dxf, or pdf) of the single-line diagram(s) and the protective relay list & trip schedule.	
	d. Single-line diagrams should be provided for both the generation plant and the interconnection substation.	

Project Interconnection - Data Request **Updated 3/17/2021**

FOR SYNCHRONOUS GENERATION

PROJECT:____

DATE: _____

(Nonexclusive Preliminary List)

*****ALL ITEMS ARE REQUIRED AND ALL RESPONSES MUST BE FILLED UNLESS NOT APPLICABLE.*****

			Response
4)		**For the Synchronous Generating Faciltiy, please provide the following data:**	
	a.	Generator manufacturer, Model, Type. Attach copy of genertor data sheet.	
	b.	Generator Characteristics (SEE "GENERATOR DATA" TAB)	
	c.	Auxillary loads (P, Q, Power Factor)	
	d.	Switching and service restoration practice	
	e.	Protection data (voltage ride-through and trip settings, frequency ride-through and trip settings etc.). Include setpoint and clearing time ranges for voltage and frequency settings.	
	f.	Description of harmonic spectrum of generator injection (order, magnitude)	
5)		**Energy Storage System, if applicable**	
	a.	Operation characteristics	
	b.	Voltage level	
	c.	Capacity (how long and how much can the battery support)	
	d.	Deployment strategy/schedule	
	e.	Energy storage system data sheet	
6)		**Please provide the following software models that accurately represent the Facility:**	
	a.	Validated PSS/E load flow model up to the point of interconnection. The PSS/E model shall include the main transformer, collection system (if applicable), generator step-up transformers (if applicable), generator, and any other components including capacitor banks, energy storage systems, DVAR, etc. Documentation on the model shall be provided.	
	b.	Validated PSS/E dynamic model for the generator; and other components including energy storage system, DVAR, etc. if applicable. The generator model shall include the generator/converter, excitation system, governor system, power system stabilizer (if applicable), and protection relays that impact its electrical performance. Generic models shall be provided. Detailed Models shall be provided for inverter-based systems (energy storage, DVAR, etc). Documentation on the model(s) shall be provided, including the PSS/E dyre file with model parameters.	
		i. Generic models shall parameterize models available within the PSS/E standard model library. Exciter model shall conform to IEEE Std 421.5. Generic models shall be selected from NERC "Acceptable_Models_list_2017-08-19.xlsx"	
		ii. Detailed models shall be supplied by the vendor/manufacturer as user-written models. The uncompiled source code for the user-written model shall be provided to ensure compatability with future versions of PSS/E. In lieu of the uncompiled source code, a compiled object file and applicable library files shall be provided in PSS/E versions 33 AND 34 format. Updates of the object file compatible with future PSS/E versions must be provided as requested for the life of the project as written in the power purchase agreement. Documentation shall include the characteristics of the model, including block diagrams, values, names for all model parameters, and a list of all state variables.	
	c.	Validated PSCAD model of the generator; and other components including energy storage system, DVAR, etc, if applicable. Documentation on the model(s) shall be provided. Refer to PSCAD Technical Memo for model requirements.	
	d.	Overlayed plots validating the performance of the three dynamic models for a three-phase fault. Plots shall include voltage, real and reactive power, real and reactive current.	
	e.	Validated Aspen Oneliner short circuit model that accurately represents the facility (including energy storage system if applicable), and is valid for all faults conditions anywhere on the Utility system. Documentation on the model(s) shall be provided. (OTHERWISE SEE ADDITIONAL TABS FOR REQUIRED INFORMATION TO MODEL INVERTER)	

Project Interconnection - Data Request **Updated 3/17/2021**

FOR SYNCHRONOUS GENERATION

PROJECT:____

DATE: ______

(Nonexclusive Preliminary List)

*****ALL ITEMS ARE REQUIRED AND ALL RESPONSES MUST BE FILLED UNLESS NOT APPLICABLE.*****

		Response
7)	**For the main transformer and generator step-up transformers, please provide:**	
	a. Transformer voltage and MVA ratings, and available taps. Attach copy of transformer test report or data sheet	
	b. The tap settings used.	
	c. The LTC Control Scheme.	
	d. Transformer winding connections and grounding used. If the transformer is not solidly grounded, provide the impedance value for the grounding method.	
	e. Positive, negative, and zero sequence impedance values.	
8)	**For the circuit breakers and fault-clearing switching devices, including the generator breakers, please provide:**	
	a. The voltage, continuous current and interrupting capability ratings.	
	b. The trip speed (time to open).	
9)	**For the power fuses, please provide:**	
	a. The manufacturer, type, size, and interrupting capability.	
	b. The minimum melt and total clearing curves.	
10)	**For the protective relaying, please provide:**	
	a. Data for the CTs used with the relaying including the manufacturer, type of CT, accuracy class, and thermal rating factor.	
	b. Data for the PTs used with the relaying including the manufacturer, type of PT, voltage ratings, and quantity.	

Updated 3/17/21

Interconnection Requirement Study - Data Request

FOR SYNCHRONOUS GENERATION

PROJECT:____

DATE: ______________________________

*****ALL ITEMS ARE REQUIRED AND ALL RESPONSES MUST BE FILLED UNLESS NOT APPLICABLE.*****

A)

Please provide the following generator machine information:	**Response**
a. Generator Base MVA	
b. Generator Rated Terminal Voltage (kV)	
c. Power Factor Range Capability	
d. Generator Reactive Power Capability Curve	
e. Generator impedance in per unit	
i. Positive sequence	
ii. Negative sequence	
iii. Zero sequence:	
f. Combined Turbine-Generator Inertia Constant, H (kW-sec / KVA)	
g. Speed damping factor (D)	
h. Generator Open-Circuit Saturation Factors. Attach Generator Saturation Curves.	
i. S(1.0):	
ii. S(1.2):	
i. Generator V-curve	

B)

Please provide the following generator reactance data (in per unit on Machine MVA Base):	**Response**		**Response**
Direct Axis		**Quadrature Axis**	
a. Synchronous - Saturated (Xdv)		a. Synchronous - Saturated (Xqv)	
b. Synchronous - Unsaturated (Xdi)		b. Synchronous - Unsaturated (Xqi)	
c. Transient - Saturated (X'dv)		c. Transient - Saturated (X'qv)	
d. Transient - Unsaturated (X'di)		d. Transient - Unsaturated (X'qi)	
e. Subtransient - Saturated (X"dv)		e. Subtransient - Saturated (X"qv)	
f. Subtransient - Unsaturated (X"di)		f. Subtransient - Unsaturated (X"qi)	
g. Negative Sequence - Saturated (X2v)			
h. Negative Sequence - Unsaturated (X2i)			
i. Zero Sequence - Saturated (X0v)			
j. Zero Sequence - Unsaturated (X0i)			
k. Leakage Reactance (Xlm)			

C)

Please provide the following generator time constants (in seconds):	**Response**		**Response**
Direct Axis		**Quadrature Axis**	
a. Transient Open Circuit (T'do)		a. Transient Open Circuit (T'qo)	
b. Subtransient Open Circuit (T"do)		b. Subtransient Open Circuit (T"qo)	
c. Transient Short Circuit (T'd)		c. Transient Short Circuit (T'q)	
d. Subtransient Short Circuit (T"d)		d. Subtransient Short Circuit (T"q)	

Instructions:
Please fill in the data in the green blanks below
(Note: This does not include the internal isolation transformer, if used)

[1] Maximum rated output power = ________ kVA

[2] Impedances in **Per Unit** based on kVA from [1]

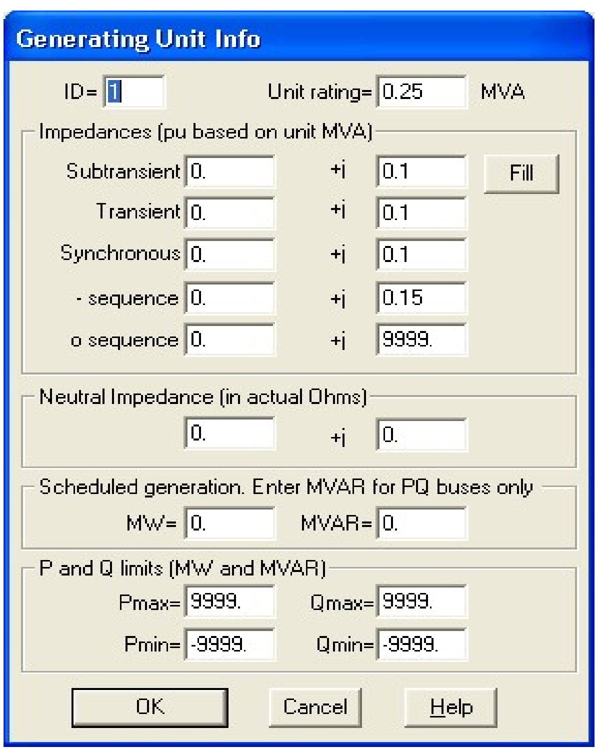
	R	X
Subtransient =		
Transient =		
Synchronous =		
Negative Sequence =		
Zero Sequence =		

[3] Neutral impedance (if any) in actual **Ohms**:

R	X

NOTE: These parameters should reflect the inverter response for all types of faults at any point on the electrical system to which the inverter is connected. This includes faults at the inverter output terminals, and also on the 138 kV transmission system. If the stated parameters do not cover this range, please state the adjustments needed to these parameters to accurately represent the inverter response across this range.

These parameters will be used to model the inverter in the Aspen Oneliner program as shown in the sample dialog box below:



Instructions:
Please fill in the data in the green blanks below
(Note: This is not required if an internal isolation transformer is not used)

[1] Transformer rated power = kVA

[2] Winding Configuration
Inverter Side = Delta/Wye
Customer Side = Delta/Wye

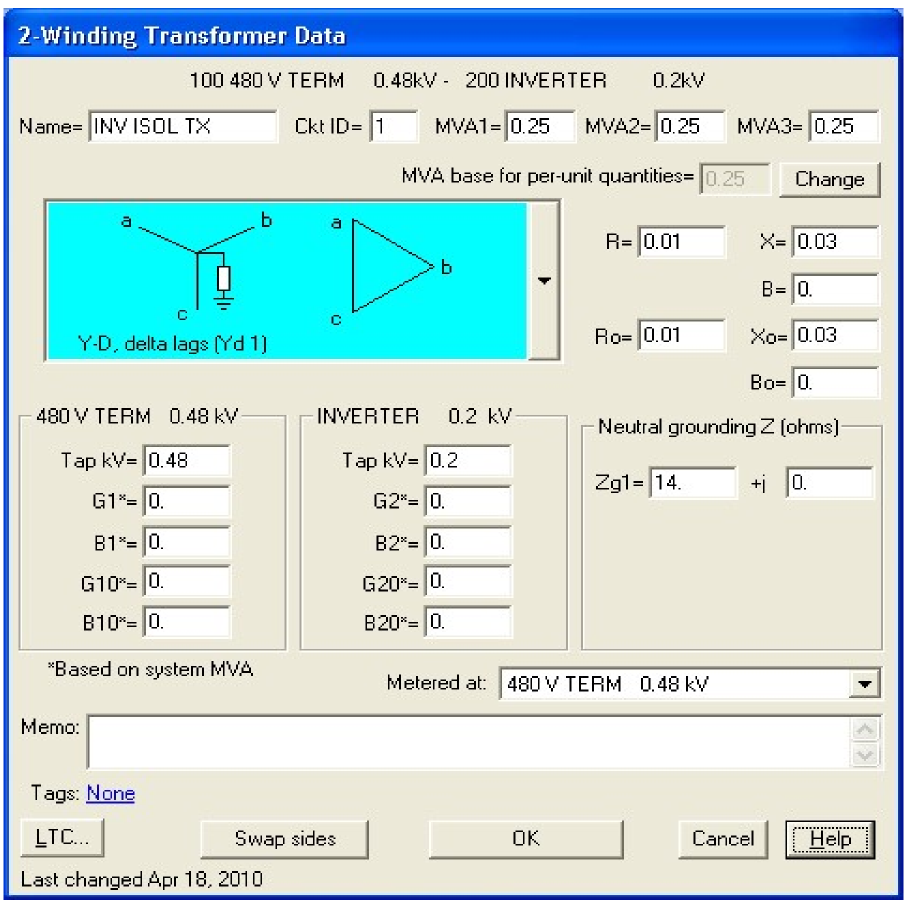
[2] Impedances in **Per Unit** based on kVA

	R	X
Positive Sequence =		
Zero Sequence =		

[3] Neutral impedance (if any) in actual **Ohms**:

R	X

These parameters will be used to model the inverter in the Aspen Oneliner program as shown in the sample dialog box below:



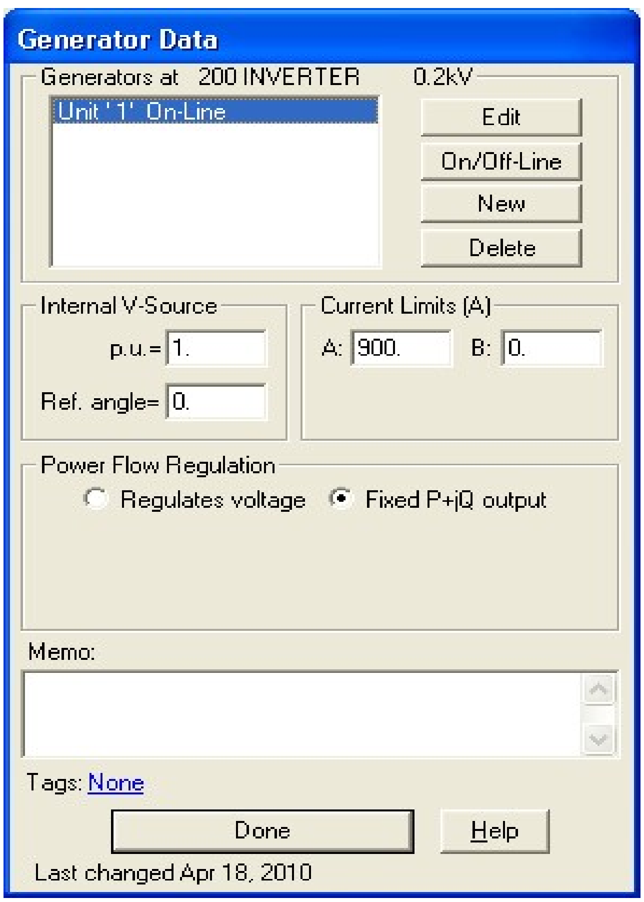
Instructions:
Please fill in the data in the green blanks below

[1] Internal open circuit voltage
Magnitude = ______ Per Unit
Angle = ______ Degrees

[2] AC Output Current Limit = ______ Amps

NOTE: These parameters should reflect the inverter response for all types of faults at any point on the electrical system to which the inverter is connected. This includes faults at the inverter output terminals, and also on the 138 kV transmission system. If the stated parameters do not cover this range, please state the adjustments needed to these parameters to accurately represent the inverter response across this range.

These parameters will be used to model the inverter in the Aspen Oneliner program as shown in the sample dialog box below:



HAWAIIAN ELECTRIC GENERATION FACILITY TECHNICAL MODEL REQUIREMENTS AND REVIEW PROCESS

August 23, 2021

Table of Contents

1 INTRODUCTION

This document summarizes requirements of generation facility technical model submittals for request for proposals for variable renewable dispatchable generation and energy storage and describes the review process for model submittals. The requirements and examples provided are based on the Company's current information as of the date of this document and are subject to change.

2 FACILITY TECHNICAL MODEL REQUIREMENTS

To fully investigate impacts of the proposed generation facility on Hawaiian Electric's system and correctly identify any mitigation measures, the proposed generation facility technical model, along with related technical documents, will need to be submitted for review prior to System Impact Study (SIS).

2.1 Overview of Submission

For all generation facility types, the technical model submittal shall include:

1. PSCAD model[1]
2. PSS/E power flow model
3. Standard Library PSS/E dynamic model
4. User defined PSS/E dynamic model, and
5. ASPEN Oneliner model

For generation facilities categorized as inverter-based resources, both Grid Following (GFL) and Grid Forming (GFM) Mode capability may be required from the project. In this case, for each project, two sets of models shall be submitted: one with the project in GFL mode, and the other with the project in GFM mode. The GFL mode technical model submittal shall follow the list above. The GFM mode technical model submittal shall include:

6. GFM PSCAD model
7. GFM User defined PSS/E dynamic model
8. GFM ASPEN Oneliner model if it differs from the GFL model

Subject to Hawaiian Electric's approval, if the manufacturer can certify current standard library dynamic models accurately represent their equipment, standard library dynamic models may be provided and used in lieu of user defined dynamic models. As an example, if the generation facility is a traditional synchronous machine, of which the technology is standardized and widely understood across the industry, it can generally be accurately represented with current standard library dynamic models and thus a user defined dynamic model will not be required.

Along with the technical models, the following documents shall also be submitted for review:

9. User manual for all technical models, including a description of GFM functionality if GFM is used.
10. Generation facility one-line diagram
11. Generation unit manufacturer datasheet(s)
12. Generation unit reactive power capability curve(s)
13. Overlaid generation facility technical model output data for three-phase fault and single-phase fault. (Sample plots are shown in Appendix A)

[1] For specific PSCAD model requirements, refer to http://www.electranix.com/wp-content/uploads/2021/02/Requirements-Rev.-10-Feb-3-2021.pdf

2.2 Background Functional Description of GFM and GFL

Grid Following and Grid Forming are terms with some ambiguity in current industrial usage. For the purpose of this document, the following definitions are provided as high level functional descriptions. For more detailed descriptions of what is required for each of these control modes, it is recommended to carefully review descriptions of the functional tests which will be performed.

Grid Following (GFL) Mode:

Grid Following is defined as follows: An inverter-based resource that relies on fast synchronization with the external grid in order to tightly control the inverter's active and reactive current outputs. If these inverters are unable to remain synchronized effectively during grid events or under challenging network conditions, they are unable to maintain controlled, stable output. Advanced versions of these devices (Advanced Inverters) can provide grid supporting functions such as: voltage and frequency ride-through, volt-VAR, frequency-Watt, volt-watt, etc.; when they are able to remain synchronized.

Grid Forming (GFM) Mode:

Grid Forming is defined as follows: GFM controls set an internal voltage waveform reference such that an inverter with the GFM control shall be able to synchronize with the grid and regulate active and reactive power generation appropriately, regardless of the grid's strength, or operate independently of other generation. An inverter with GFM control shall immediately respond to grid disturbances to support stability of the grid and maintain its own control stability during the system disturbances.

2.3 General requirements for all technical models

All technical models need to represent the whole generation facility, not only a generation unit such as one inverter or as separate files representing pieces of the facility. At minimum, the following equipment shall be included in the single whole generation facility model:

1. Generation unit, such as inverter with DC side model, or a rotating machine with model of exciter and governor.
2. Step up transformer, with correct impedances and winding configuration
3. Collection system, aggregated per WECC guidance[2]
4. Main interconnection transformer, or GSU, with its tap changer if applicable, including correct impedances and winding configuration
5. Grounding transformer if used
6. VAR compensation device, such as cap bank or STATCOM, if applicable
7. Power plant controller (not for ASPEN model)
8. Documentation
9. Gen-tie line (as applicable)

[2] https://www.wecc.org/Reliability/WECCWindPlantPowerFlowModelingGuide.pdf

Equivalent or aggregated representations of the collection system, generator step-up transformers, and inverter systems are acceptable if it can accurately represent the generation facility and its response characteristics.

2.4 Requirements for generation facility PSCAD model

In addition to the general requirements mentioned above, the generation facility PSCAD model shall satisfy requirements as described in the latest version of the PSCAD Model Requirements document from Electranix Corporation (https://www.electranix.com/the-electranix-library/) and provided by Hawaiian Electric.

The control implementation (e.g., turbine controls, inverter controls, protection and measurement algorithms, and plant-level controller) in the generation facility PSCAD model shall implement the actual control code from the equipment. The PSCAD model shall provide output channel of voltage and frequency measured by the Facility and used for Facility's control and protection.

For the generation facility with grid-forming control, a document which describes the general mechanism and implementation of the grid-forming control is required.

2.5 Requirements for generation facility PSS/E power flow model

The generation facility PSS/E power flow model shall be provided for PSS/E versions 33, 34 and 35 . Besides the general requirements mentioned above, the following modeling data shall be provided in the model:

1. Conductor
    a. Impedance, both positive sequence and zero sequence
    b. Rating: Rating A – normal rating, and Rating B – emergency rating
2. Transformer
    a. Nominal voltages of windings
    b. Impedance data: specified R and X
    c. Tap ratios
    d. Min and Max tap position limits
    e. Number of tap positions
    f. Regulated bus
    g. Ratings: Rate A – normal rating; Rate B – emergency rating
    h. Winding configuration
3. Reactive power compensation, if applicable
    a. Fixed Shunts: G-Shunt (MW), B-Shunt (MVAr)
    b. Switched Shunts: Voltage limits (Vhi and Vlow), mode of operation (fixed, discrete, continuous), regulated bus, Binit (MVAr), steps and step size (MVAr)
4. Generation unit
    a. Pmax
    b. Pmin
    c. Qmax
    d. Qmin
    e. Name plate MVA

   f. Transformer data: R Tran, X Tran, and Gentap.
   g. Voltage control point

2.6 Requirements for generation facility user defined PSS/E dynamic model

The submitted user defined PSS/E dynamic model shall meet the following requirements:

1. The generation facility PSS/E dynamic model shall be provided for PSS/E versions 33, 34 and 35.
2. The project shall be modeled at full output per the project's Interconnection Request.
3. User defined dynamic models must accurately model all the relevant control modes and characteristics of the equipment, such as:
   a. All available voltage/reactive power control modes
   b. Frequency/governor response control modes
   c. Voltage and frequency ride-through characteristics
   d. Power plant controller or group supervisory functionality
   e. Appropriate aggregate modeling capability
   f. Charging mode if applicable (e.g., for a battery energy storage device)
4. Dynamic model source code (.flx, .for, .f90, .f, etc.), or dynamic linked library (.dll), and PSS/E dyr file shall be provided.
5. User defined dynamic model plant-specific settings shall comply with requirements listed in the Power Purchase Agreement, including ride-through thresholds and other specified control settings if applicable.
6. User defined dynamic models related to individual units shall be editable in the PSS/E graphic user interface. All model parameters (CONS, ICONS, and VARS) shall be accessible and shall match the description in the model's accompanying documentation.
7. User defined dynamic models shall have all their data reportable in the "DOCU" listing of dynamics model data, including the range of CONS, ICONS, and VARS numbers. Models that apply to multiple elements (e.g., park controllers) shall also be fully formatted and reportable in DOCU.
8. User defined dynamic models shall be capable of correctly initializing and run through the simulation throughout the range of expected steady state starting conditions without additional manual adjustments.
9. User defined dynamic models shall be capable of allowing all documented (in the model documentation) modes of operation without error.
10. User defined dynamic model shall be accompanied by the following documentation:
    a. A user's guide for each model
    b. Appropriate procedures and considerations for using the model in dynamic simulations
    c. Technical description of characteristics of the model
    d. Block diagram for the model, including overall modular structure and block diagrams of any sub-modules
    e. List of plant-specific settings, which may include:
        i. Ride-through thresholds and parameters
        ii. Plant-level voltage controller settings
        iii. Power ramp rate settings
        iv. ICON flag parameters for specific control modes

v. Deadbands
vi. Initial State of Charge (SOC)

f. Values, names and detailed explanation for all model parameters
g. List of all state variables, including expected ranges of values for each variable

2.7 Requirements for generation facility generic PSS/E dynamic model

The submitted generic PSS/E dynamic model should meet the following requirements:

1. All generic PSS/E dynamic models must be standard library models in PSS/E.
2. The generation facility PSS/E dynamic model shall be provided for PSS/E versions 33, 34 and 35.
3. The project shall be modeled at full output per the project's Interconnection Request.
4. Generic dynamic models must accurately model all the relevant control modes and characteristics of the equipment, such as:
    a. All available voltage/reactive power control modes
    b. Frequency/governor response control modes
    c. Voltage and frequency ride-through characteristics
    d. Power plant controller or group supervisory functionality
    e. Appropriate aggregate modeling capability
    f. Charging mode if applicable (e.g., for a battery energy storage device)
5. PSS/E dyr file shall be provided.
6. Generic dynamic models' plant-specific settings should comply with requirements listed in the Power Purchase Agreement, including ride-through thresholds and other specified control settings if applicable.
7. Generic dynamic models shall be capable of correctly initializing and run through the simulation throughout the range of expected steady state starting conditions without additional manual adjustments.
8. Generic dynamic models shall be accompanied by the following documentation:
    a. A user's guide for each model
    b. Appropriate procedures and considerations for using the model in dynamic simulations
    c. Technical description of characteristics of the model
    d. List of plant-specific settings, which may include:
        i. Ride-through thresholds and parameters
        ii. Plant-level voltage controller settings
        iii. Power ramp rate settings
        iv. ICON flag parameters for specific control modes
        v. Deadbands
        vi. Initial State of Charge (SOC)

2.8 Requirements for generation facility ASPEN model

Besides the general requirements, validation results of three-phase fault current from the generation unit represented in the generation facility ASPEN Oneliner model shall be provided.

3 GENERATION FACILITY TECHNICAL MODEL REVIEW PROCESS

To review the generation facility technical model, the following procedures are performed in the PSCAD and PSS/E environment. A review of the results will be documented and provided to the Customer for confirmation of model acceptance or further model updates.

3.1 Model review in PSCAD

1) Review model data against latest version of the PSCAD Model Requirements document from Electranix Corporation (https://www.electranix.com/the-electranix-library/) provided by Hawaiian Electric. In this step, it will be determined whether the model is complete, generation facility settings are according to the Power Purchase Agreement, and if the model can be compiled and run without any error. Checklists are provided in this document which are useful for both preparing a model submission, and for reviewing a model submission.
2) Initialization test:
   In this step, the generation facility PSCAD model will be determined whether the model initialization is acceptable. Hawaiian Electric requires that:
   1) The PSCAD model shall initialize as quickly as possible (e.g. <1-3 seconds) to user defined terminal conditions.
   2) Project PSCAD model shall initialize properly and that the same power flow and voltage conditions shall be observed between the PSCAD and PSS/E models after initialization.
3) Voltage and frequency ride-through tests:
   In this step, the generation facility PSCAD model ride-through performance will be reviewed by performing voltage and frequency ride-through simulations in PSCAD. The review will focus on the generation facility model dynamic response during and after ride-through and generation facility trip time.
4) Fault simulation tests:
   Two types of fault tested at the Point of Interconnection bus of the generation facility will be performed in this step.
   i) 3-phase to ground fault with 6-cycle clearing time (same as the PSS/E ring down model test described in the following section).
   ii) 1-phase to ground fault simulation with 6-cycle clearing time.

   In this test, fault current contribution from the generation facility observed in the simulation will be reviewed by comparing it against the generation facility technical document.

3.2 Model review in PSS/E

1) **Model data review:**
   Review model data based on the requirements for PSS/E power flow and dynamic model provided by Hawaiian Electric. In this step, the review determines whether the model is complete, generation facility settings is according to the PPA, and model can be compiled and run without any error.

a. Steady State Model Data Review

Review the ratings and impedances of all equipment in the ASPEN Oneliner, PSS/E and PSCAD models and check for discrepancies.

Table 1. Steady State Model Data Review

Equipment	Comments
Gen-Tie Line	PSS/E, PSCAD and ASPEN models should match
Main Power Transformer Impedance	PSS/E, PSCAD and ASPEN models should match
Main Power Transformer Impedance	PSCAD and ASPEN models should match
PV Collector System Data	PSS/E, PSCAD and ASPEN models should match
BESS Collector System Data	PSS/E, PSCAD and ASPEN models should match
Inverter Pad Mount Transformer Impedance	PSS/E, PSCAD and ASPEN models should match
Inverter Pad Mount Transformer Configuration	PSCAD and ASPEN models should match
Inverter Power Flow Data	PSS/E and PSCAD models should match
Voltage Control Point	PSS/E and PSCAD models should match

b. Dynamic Data Review

Compare the various dynamic model parameters and note any discrepancies.

Table 2. Dynamic Model Data Review

Equipment	Comments
Power Plant Controller (PPC)	Review number of PPCs. Should represent actual setup of plant when in service.
Control Flags	PSS/E and PSCAD control flags should match.
Control Bus/Point of Measurement	Control buses should match in PSS/E and PSCAD models.
Frequency Control Dead Band	The frequency thresholds for primary and secondary control should match in the PSCAD and PSS/E models.
Initial State of Charge (SOC)	Make sure the initial state of charge is set up correctly to prevent initialization issues.
Voltage and Frequency Ride Through	The voltage and frequency ride through settings should match in the PSS/E user-written, PSS/E generic and PSCAD models.
P/Q priority data	The P/Q priority flags should match in the PSS/E user-written, PSS/E generic and PSCAD models

2) Flat start test:

PSS/E models shall initialize correctly and be capable of successful "flat start" testing using the 20 Second No-Fault simulation: This test consists of a 20 second simulation with no disturbance applied. Flat run in a two-machine system (one machine is a synchronous machine, e.g., GENCLS model, and the other machine is a project's model.)

3) **Ring down test:**
PSS/E models shall initialize correctly and be capable of successful "ring down" testing using the 60 Second Disturbance Simulation: This test consists of the application of a 3-phase fault for 6 cycles at POI bus, followed by removal of the fault without any lines being tripped. The simulation is run for 60 seconds to allow the dynamics to settle.

4) **Voltage and frequency ride-through tests:**
In this step, the generation facility PSS/E model ride-through performance will be reviewed by performing voltage and frequency ride-through simulation in PSS/E. The review will focus on the generation facility model dynamic response during and after ride-through and generation facility trip time. **The procedures and values listed in this section are illustrative and serve as examples only; ride-through durations shall be tested against the minimum requirements outlined in the respective PPA.**

a. Voltage Ride-Through

- In these simulations, the POI voltage is varied to test the facility's ride-through capabilities and responses to POI voltage excursions. In the PSS/E simulations, two sets of tests are performed: one for testing the ride-through capabilities and the other for testing the responses to voltage excursions. These two sets of tests are similar, except that the grid equivalent representation is different. For the ride-through tests, the grid equivalent is represented by a generator with a very large MVA, which connects to the POI bus directly.
    - *As an example, for the voltage excursion response tests, the grid equivalent may be represented by a 200 MVA generator (actual MVA rating dependent on POI, please consult the Company for representative values) which connects to the POI through a branch with a reactance of 0.1 p.u.*
- In the PSCAD simulations, the focus is on testing the facility's reactive power responses to POI voltage excursions, and not on testing the voltage ride-through capability.

Table 3 shows the voltage excursions that will be simulated in the PSCAD tests.

Table 3. Voltage	**Duration (s)**
1.20	0.8
1.10	2.0
0.88	2.0
0.70	2.0

Each of the above discussed tests were performed for the following three generation dispatches:

i. PV output only: In this dispatch, the PV unit is at maximum output and the BESS unit is online at 0 MW.
ii. BESS output only: In this dispatch, the BESS unit is discharging at maximum output and the PV unit is online at 0 MW.

iii. PV charging BESS: In this dispatch, the PV unit is at its maximum output and is charging the BESS at its minimum level.

b. Frequency Ride-Through

- In these simulations, the system frequency is varied to test the facility's responses to grid's frequency excursions. In the PSS/E tests, high and low frequency excursions are simulated to mimic the frequency ride through thresholds specified in the PPA and the response of the facility is observed. Both the frequency ride-through capability of the facility and its active power response to frequency excursions are tested in the PSS/E simulations.
- In the PSCAD simulations, the focus is on testing the facility's active power responses to frequency excursions, and not on testing the frequency ride-through capability. Table 4 and Table 5 show example frequency excursions that are simulated in the PSCAD tests.

Table 4. Frequency Excursions for PSCAD High Frequency Response Test

Frequency Level (Hz)	Duration (s)
60.1	2.0
63.0	2.0

Table 5. Frequency Excursions for PSCAD Low Frequency Response Test

Frequency Level (Hz)	Duration (s)
59.9	2.0
56.0	2.0

5) Expected Model Performance

a. Matching steady-state model parameters between the PSS/E user-written, generic models and the PSCAD model.
b. Matching control options between the three types of models.
c. Matching voltage and frequency ride-though parameters between the three types of models. The settings should meet the ride-through requirements specified in the PPA.
d. Flat run results do not show any movement for any of the three models.
e. Ring-down simulation results show stable and proper responses, and the responses from the three models should show reasonable matches.
f. Ride-through simulation results should show stable and proper responses, and the responses should show reasonable matches. The ride through performance should meet the PPA requirements.

3.3 GFM Model review in PSCAD and PSS/E

The tests described below will be performed in addition to the GFL model tests described in section 3.1.

Test notes:

- Applicable for generation facilities which have grid-forming control capability
- Assumption is that BESS has available energy and is dispatched suitably for the tests
- Each test will be repeated with three initial operating conditions, as applicable (PV output only, BESS output only, PV charging BESS)
- The project should be configured to be in GFM mode throughout these tests

1) **Able to black start and operate in an electrical island (applicable if project is providing black start capability):**
   Test sequence: energize main power transformer from project side, then connect project to a load, then apply a bus fault at the POI, then remove the fault. Expected results: voltage and frequency should be stable and settle back to close to their nominal values after the disturbances.
2) **Loss of the last synchronous machine:**
   Test system will be a three-machine system including: a synchronous machine modeled by GENROU with a simple excitation system model (e.g., SCRX) and a simple governor model (e.g., TGOV1), a load with both real and reactive components, and duplicates of a project's model. Duplicates of a project's model are utilized here to check if the project is able to share real and reactive power properly with other generators. Test event: trip the synchronous generator. Expected results: voltage and frequency should be stable and settle back to close to their nominal values after the disturbance, within the tolerance of the droop and deadband settings.
3) **Weak grid operation:**
   Test system is the project plant model and an equivalent voltage source behind an impedance connected at the POI. The test will be to gradually decrease MVA of the equivalent voltage source within a range and check if the project's model is able to work with the studied MVA range.
4) **Able to operate in harmony with other converter resources and synchronous machines:**
   Test system is the three-machine system including: a synchronous machine modeled by GENROU with a simple excitation system model and a simple governor model, a load with both real and reactive components, and duplicates of a project's model. Simulation tests to be performed may include load step up/down, ringdown, voltage ride through and frequency ride-through tests. Expected results: voltage and frequency should be stable and settle back to close to their nominal values after the disturbances.
   Particularly related to frequency control characteristics, we will test for configurable frequency droop control and configurable deadband characteristics. The frequency deadband should be settable in the range from +/- 0.01 Hz to +/- 1.0 Hz and the frequency droop shall be settable in the range of 0.1% to 10% with a typical value of 4%. A sample characteristic of frequency droop control with deadband is shown in Figure 1.

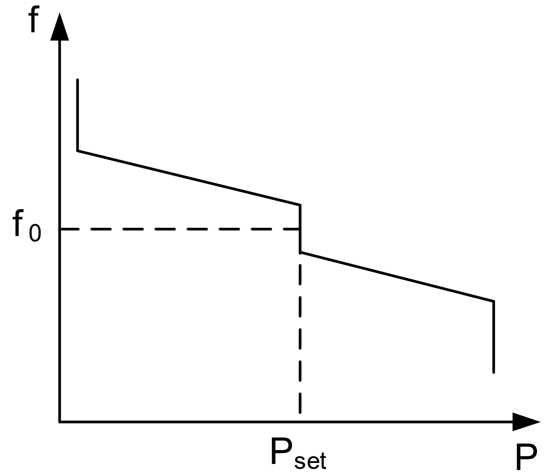


Figure 1 – Frequency Droop Control Characteristic with Deadband

5) **Switching from an electrical island to a grid-connected configuration while in GFM mode (dependent on specific project technology and controls)**
Test system is the two-machine system. Test sequence: energize main power transformer from project side, then connect project to a load (if project model does not have black-start capability, the plant will be initialized using a voltage source which will be switched out after initialization). At this point, the project will be operating in an island. Then switch in the synchronous generator. Expected results: voltage and frequency should be stable and settle back to close to their nominal values after the disturbances.

Tests to be performed for PSS/E models only

6) **Reduction in frequency deviation in GFM mode**
Test system will be a relevant HECO island system model. Test event is loss of a large generator. Project model will be in GFL mode and GFM mode. Result: less degree of frequency deviation is expected when project is in GFM mode than when the project is in GFL mode.

ASPEN Model Check

7) **A review of the ASPEN Oneliner generation models will be performed.**
As mentioned above, two models are expected for each project: one model for GFL mode, and the other for GFM mode. Documentation associated with the models should be provided. The model review will check if the components of a project are modeled properly, such as transformers, equivalent collector system, equivalent generator, etc., and that the model data are consistent to the PSS/E and PSCAD model data. A fault simulation test will also be performed in a two-machine system. Total current at the fault location and contribution from each machine will be reviewed and documented.

4 TYPICAL ISSUES IDENTIFIED FROM THE FACILITY MODEL SUBMITTALS DURING THE PAST RFP PROCESS

1. **Missing documentation**
   Only generation technical facility models are submitted, but no model user manual or any other documentation. Without model documentation, it is very difficult to know the correct procedures of using the technical models and identifying issues during the review.
2. **Model incompleteness**
   Often, the model of a single generation unit, such as an inverter, is submitted instead of model of the whole generation facility, which is insufficient. The model of the generation facility should include models for all equipment listed in the section of "General requirements for all technical models".
3. **Settings in the model**
   Type issues in this category are:
   - The PSCAD (GFL and/or GFM) and PSS/E model ride-through settings are not consistent with the minimum settings defined in the Power Purchase Agreement.
   - Generation MW is not set as defined.
   - Model is set for 50 Hz instead of 60 Hz
4. **Model function issues**
   Some models do not function as expected during different test scenarios. For example:
   - Fault current contribution from the generation facility is higher than what is described in the generation facility datasheet
   - Generation level is not stable with provided settings during the initialization test
   - Inadequately damped oscillations observed in the ringdown test
   - Ride-through performance does not reach minimum requirements defined in the Power Purchase Agreement
5. **Power Plant Controller (PPC)**
   Often, the PPC control had not yet been fully considered when models are submitted, which results in improperly configured PPC controls, or model submissions missing the PPC altogether. The PPC(s) included in the facility model should include coordination functionality between the plant components, and should represent the actual planned implementation.

REFERENCE

[1] New England Iso Planning procedure – Interconnection planning procedure for generation and elective transmission upgrades
[2] ERCOT Planning Guide, 2019
[3] PJM MOD-032 Steady State, Dynamics, and Short Circuit Modeling Data Requirements and Reporting Procedures Document

APPENDIX A: SAMPLE OVERLAID GENERATION FACILITY TECHNICAL MODEL OUTPUT PLOT FOR THREE-PHASE FAULT

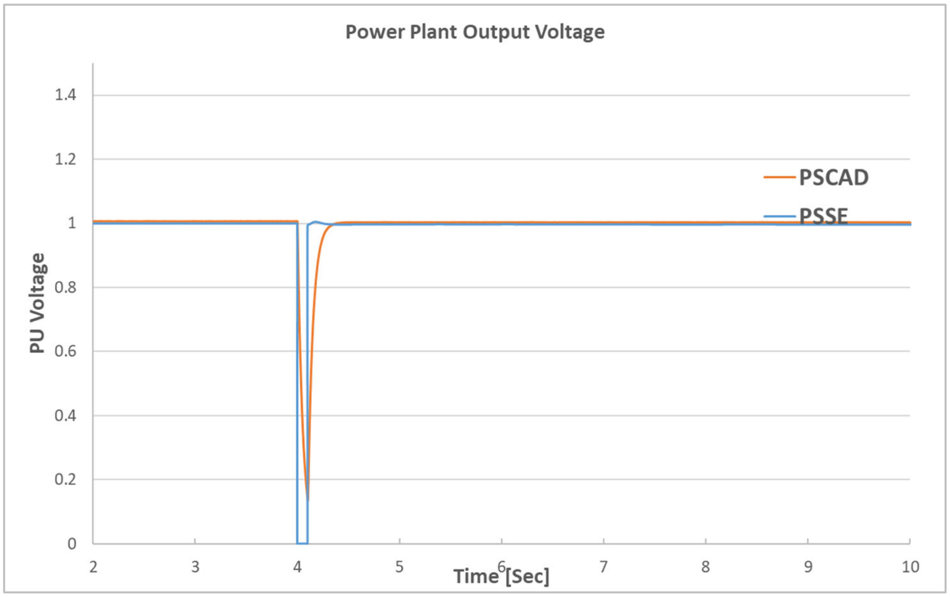


Figure 1: Overlaid plot for power plant voltage

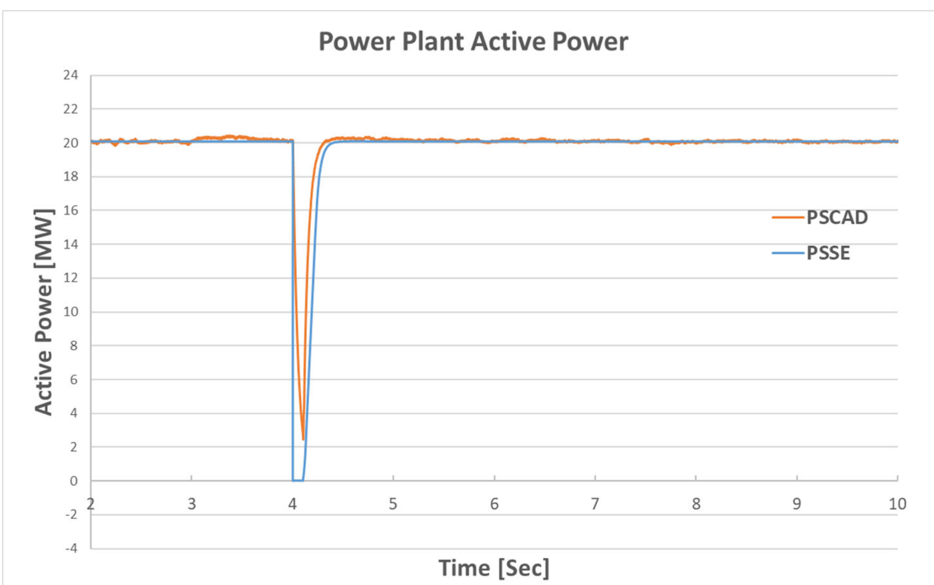


Figure 2: Overlaid plot for power plant active power generation

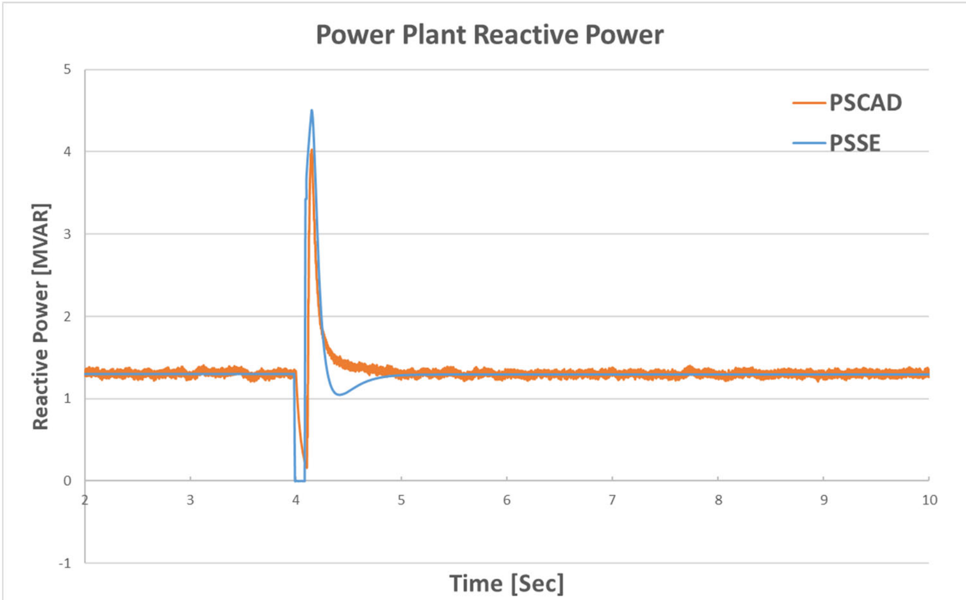


Figure 3: Overlaid plot for power plant reactive power generation

APPENDIX B: SAMPLE TEST SYSTEM TOPOLOGYINFORMATION

On weak grids such as island systems, it is important to test the models using a representative high Thevenin equivalent impedance.

A typical topology of testing circuit which represents Hawaiian Electric system for 46 kV project is shown in Figure 4. Sample 46 kV Thevenin equivalent impedance is available upon request for model testing.

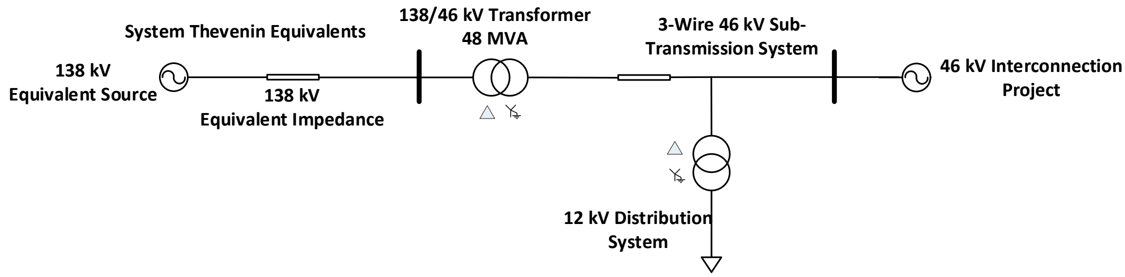


Figure 4: Testing circuit single line diagram for 46 kV project

A typical topology of testing circuit which represents Hawaiian Electric system for 138 kV project is shown in Figure 5. Sample 138 kV Thevenin equivalent impedance is available upon request for model testing.

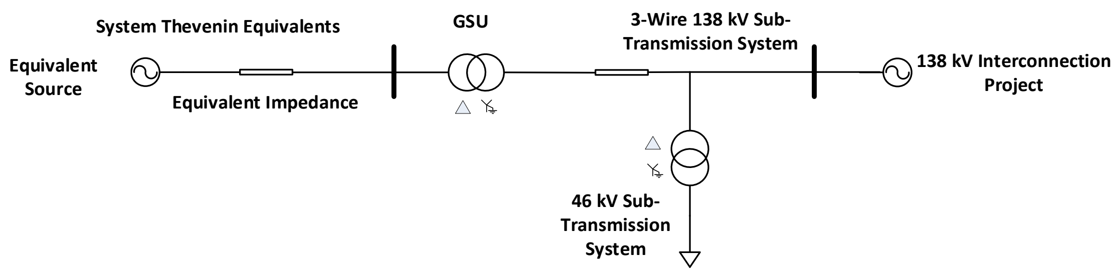


Figure 5: Testing circuit single line diagram for 138 kV project

Appendix B Attachment 4
Stage 3 Model and Interconnection Requirements Study (IRS) Scope

Island	Oahu	Oahu	Oahu
Size	Connecting to 138kV Wind	Connecting to 138kV PV+ESS, Wind+ESS, or Standalone ESS	Connecting to 138kV Synchronous Generation
Models	PSS®E Generic, PSS®E User Defined, PSCAD, and ASPEN.	Grid Forming Models • PSS®E Generic, PSS®E User Defined, PSCAD, and ASPEN.	PSS®E Generic, PSCAD, and ASPEN.

Interconnection Requirement Study Scope	Tasks
	(Include selected tasks in the IRS. Exclude tasks that are unselected)
	☒ Project Data Requirements and Facility Technical Model Review
	☒ Review of Existing System Performance (Base-Case)
	☒ Develop Project Model (IRS Case)
	☒ Steady-State Power Flows
	  ☒ Reverse Power Flow
	  ☒ Reactive Power Requirements
	☒ Protection Review
	☒ Voltage Flicker
	☒ Voltage Transients (In-Rush Current)
	☒ System Stability
	  ☒ PSSE Analyses
	  ☒ PSCAD Analyses for Weak Grid Conditions
	  ☐ Grid Forming Analyses
	☒ Ride-Through Requirements
	☒ Unintended Islands
	  ☒ Transient Overvoltage (TrOV)
	  ☒ Unintended Islands Fault Overvoltage (GFOV)
	☐ Harmonics
	  ☐ Harmonics Model Analysis
	  ☐ Harmonics Monitoring Assessment
		Tasks
		(Include selected tasks in the IRS. Exclude tasks that are unselected)
		☒ Project Data Requirements and Facility Technical Model Review
		☒ Review of Existing System Performance (Base-Case)
		☒ Develop Project Model (IRS Case)
		☒ Steady-State Power Flows
		  ☒ Reverse Power Flow
		  ☒ Reactive Power Requirements
		☒ Protection Review
		☒ Voltage Flicker
		☐ Voltage Transients (In-Rush Current)
		☒ System Stability
		  ☒ PSSE Analyses
		  ☒ PSCAD Analyses for Weak Grid Conditions
		  ☒ Grid Forming Analyses
		☒ Ride-Through Requirements
		☒ Unintended Islands
		  ☒ Transient Overvoltage (TrOV)
		  ☒ Unintended Islands Fault Overvoltage (GFOV)
		☐ Harmonics
		  ☐ Harmonics Model Analysis
		  ☐ Harmonics Monitoring Assessment
			Tasks
			(Include selected tasks in the IRS. Exclude tasks that are unselected)
			☒ Project Data Requirements and Facility Technical Model Review
			☒ Review of Existing System Performance (Base-Case)
			☒ Develop Project Model (IRS Case)
			☒ Steady-State Power Flows
			  ☒ Reverse Power Flow
			  ☒ Reactive Power Requirements
			☒ Protection Review
			☐ Voltage Flicker
			☐ Voltage Transients (In-Rush Current)
			☒ System Stability
			  ☒ PSSE Analyses
			  ☒ PSCAD Analyses for Weak Grid Conditions
			  ☐ Grid Forming Analyses
			☒ Ride-Through Requirements
			☒ Unintended Islands
			  ☒ Transient Overvoltage (TrOV)
			  ☒ Unintended Islands Fault Overvoltage (GFOV)
			☐ Harmonics
			  ☐ Harmonics Model Analysis
			  ☐ Harmonics Monitoring Assessment

Reference Single Line Diagram	See Appendix H	See Appendix H	See Appendix H

Appendix B Attachment 4
Stage 3 Model and Interconnection Requirements Study (IRS) Scope

Island	O`ahu	O`ahu	O`ahu
Size	Connecting to 46kV Wind	Connecting to 46kV PV+ESS, Wind+ESS, or Standalone ESS	Connecting to 46kV Synchronous Generation
Models	PSS®E Generic, PSS®E User Defined, PSCAD, and ASPEN.	Grid Forming Models ○ PSS®E Generic, PSS®E User Defined, PSCAD, and ASPEN.	PSS®E Generic, PSCAD, and ASPEN.
Interconnection Requirement Study Scope	**Tasks** (Include selected tasks in the IRS. Exclude tasks that are unselected) ☒ Project Data Requirements and Facility Technical Model Review ☒ Review of Existing System Performance (Base-Case) ☒ Develop Project Model (IRS Case) ☒ Steady-State Power Flows ☒ Reverse Power Flow ☒ Reactive Power Requirements ☒ Protection Review ☒ Voltage Flicker ☒ Voltage Transients (In-Rush Current) ☒ System Stability ☒ PSSE Analyses ☒ PSCAD Analyses for Weak Grid Conditions ☐ Grid Forming Analyses ☒ Ride-Through Requirements ☒ Unintended Islands ☒ Transient Overvoltage (TrOV) ☒ Unintended Islands Fault Overvoltage (GFOV) ☐ Harmonics ☐ Harmonics Model Analysis ☐ Harmonics Monitoring Assessment	**Tasks** (Include selected tasks in the IRS. Exclude tasks that are unselected) ☒ Project Data Requirements and Facility Technical Model Review ☒ Review of Existing System Performance (Base-Case) ☒ Develop Project Model (IRS Case) ☒ Steady-State Power Flows ☒ Reverse Power Flow ☒ Reactive Power Requirements ☒ Protection Review ☒ Voltage Flicker ☐ Voltage Transients (In-Rush Current) ☒ System Stability ☒ PSSE Analyses ☒ PSCAD Analyses for Weak Grid Conditions ☒ Grid Forming Analyses ☒ Ride-Through Requirements ☒ Unintended Islands ☒ Transient Overvoltage (TrOV) ☒ Unintended Islands Fault Overvoltage (GFOV) ☐ Harmonics ☐ Harmonics Model Analysis ☐ Harmonics Monitoring Assessment	**Tasks** (Include selected tasks in the IRS. Exclude tasks that are unselected) ☒ Project Data Requirements and Facility Technical Model Review ☒ Review of Existing System Performance (Base-Case) ☒ Develop Project Model (IRS Case) ☒ Steady-State Power Flows ☒ Reverse Power Flow ☒ Reactive Power Requirements ☒ Protection Review ☐ Voltage Flicker ☐ Voltage Transients (In-Rush Current) ☒ System Stability ☒ PSSE Analyses ☒ PSCAD Analyses for Weak Grid Conditions ☐ Grid Forming Analyses ☒ Ride-Through Requirements ☒ Unintended Islands ☒ Transient Overvoltage (TrOV) ☒ Unintended Islands Fault Overvoltage (GFOV) ☐ Harmonics ☐ Harmonics Model Analysis ☐ Harmonics Monitoring Assessment
Reference Single Line Diagram	See Appendix H	See Appendix H	See Appendix H

DETAILED INSTRUCTIONS FOR COMMUNITY OUTREACH PLAN

- The Community Outreach Plan should be as current and explanatory as possible.
    - The Community Outreach Plan information must be included in the information Proposers selected to the Final Award Group make available on their website when the website is posted publicly.
    - The Company will also require (monthly/bi-monthly) project status updates from Proposers to verify the implementation of the COP and will ensure Proposers provide accessible opportunities for community members and stakeholders to provide public comment as required by the RFP.
- Proposers selected to the Final Award Group must develop a public Project website, which shall include all the information on the Community Outreach Plan table for their Project.
- Proposers must develop Project presentations that include all the information on the Community Outreach Plan table (sample template provided).
- Due to the uncertainty of the duration of the COVID-19 pandemic, all Proposers are required to plan for both in-person and virtual community meetings. As we near the dates that community meetings are scheduled, in the interest of public health and safety, the conditions at the time will determine if in-person meetings or virtual meetings will be required.
    - Virtual community meetings can either be community televised, or online, but must incorporate technology that allows for live engagement and interaction between the Proposer and community participants.
- Proposers must communicate important information about the Project with stakeholders in advance of community meetings.
- Proposers must perform media outreach (earned media) and advertising (paid media) to raise community awareness of any public meeting. Media advisories (sample attached) must be issued to the following media and organizations a minimum of 30 days prior to a public meeting. Media advisories do not need to be reviewed and approved by Hawaiian Electric, but must be shared with Hawaiian Electric for awareness.
    - For Oahu Projects
        - Star Advertiser
        - Civil Beat
        - Hawaii News Now
        - KHON2 News
        - KITV4 News
        - Neighborhood Boards
    - For Maui Projects
        - Maui News
        - Maui Now
        - Civil Beat
        - Hawaii News Now
        - KHON2 News
        - KITV4 News
    - For Hawaii Island Projects
        - Hawaii Tribune Herald
        - West Hawaii Today
        - Civil Beat
        - Hawaii News Now
        - KHON2 News
        - KITV4 News

- Advertisements must be placed in area community publications.
  - Guidance from the Company can be provided upon request
  - Information in the ads must be consistent with the media advisory
- Public comments in support and in opposition to the proposed Project must be compiled and filed verbatim with the Public Utilities Commission.
- Proposers must work with and inform neighboring communities and stakeholders to provide community members timely information during ALL phases of the project, which must include, but not be limited to the Power Purchase Agreement negotiation period, the permitting process periods, and throughout construction.
- A documented community benefits package highlighting the distribution of funds must be developed by Proposers for Hawaiian Electric's review. This document will be made public on each Proposer's website and must demonstrate how funds will directly address needs in the host community to benefit community members.
  - The community benefits package must include documentation of each Proposer's community consultation and input collection process to define host community needs, along with community-supported actions and/or programs aimed at addressing those needs.
  - Preference will be given to Proposers that commit to setting aside a larger amount or commit to providing other benefits (including but not limited to creating local jobs, payment of prevailing wages, or improving community infrastructure).
  - Specify the amount of funds ($) that the Proposer will commit on an annual basis to provide as community benefits. As described in Section 4.4.2 of the RFP, at a minimum, Proposers should commit to setting aside $3,000 per MW, up to $200,000 per year, for community benefits.
  - The Proposer may choose to identify and select an eligible non-profit organization to serve as the administrator for the duration of the contract term responsible for ensuring the project's community benefit is appropriately disbursed. Should a Proposer need an example of the use of a community benefit funding host, the Company will provide such example(s) upon request.
    - If Proposers opt to work with a 501(c)(3) non-profit organization(s) to host and/or distribute community benefit funding, the names of the organization(s) must be provided with documentation 90 calendar days upon signing of the appropriate Stage 3 Contract.
      - Name of non-profit organization(s)
      - Letter from non-profit organization, signed by organization's executive and Board Chair agreeing to serve as community benefit fund administrator for the duration of the contract term
      - Relevant experience of non-profit
      - Years of existence of non-profit
  - Any other community benefits (in addition to community funding) that will provide direct benefit to the Project's host community
- Should any COVID-19 related events interfere with the Proposer's ability to perform the listed actions, Proposer should inform the Company immediately of such effects for Company's consideration and guidance, and possible proposal of alternate actions.

CONTACT: NAME, 808.XXX.XXXX **FOR IMMEDIATE RELEASE**

Email address Date

Media Advisory: Title

Project description to be drafted by developer. Description must include the location of proposed project and supporting background information.

Date: TBD

Time: TBD

Location: TBD

Purpose: To share information about a TYPE (e. g. CBRE solar, etc.) renewable energy project proposed to be developed in COMMUNITY near AREA REFERENCE and to solicit public comments to be filed with the Public Utilities Commission.

Contact: For more information, call 808.XXX.XXXX or visit (website/social media)

# # #

Project Name

Proposer Name

Project Benefits

- Details

Community Benefits

- Details

Proposed Facility Location in/near what City/Area

- Map
- Dimensions of proposed project
- Include all project components

Project Description

- Details

Site Layout Plan

- Project Layout
- Project Visual Simulations
  - Multiple public vantage points

Interconnection Route

- Map

Required Government Permits and Approvals

- Preliminary Schedule
- Opportunities for public comment

Environmental Impacts

- Preliminary environmental assessment of the site (including any pre-existing environmental conditions)

Cultural Impacts

- Identify any cultural, historic or natural resources that will be impacted by the project
- Describe the potential impacts on these resources
- Identify measures to mitigate such impacts.

Construction Related Updates

- Plan for reporting construction schedules and activities
  - Including resulting impacts (ex. traffic, noise, and dust) and mitigation plans
  - Begins at least one month prior to the start of scheduled work
    - To extend throughout the construction and development of the project

Local Labor and Prevailing Wage Commitment (if any)

- Detailing Proposer's commitment, if any, that 80% of non-supervisory construction and operations workers' hours associated with the construction or repowering of a Project will be paid at the prevailing wage equivalent under HRS Chapter 104 during all periods of construction.
- Describing commitment, if any, to hire qualified construction, operations, and maintenance works who reside in the county where the Project is being constructed, and the State of Hawaii, in that order, before hiring non-resident labor.

Community Benefits Package

- Specify the amount of funds ($) that the Proposer will commit on an annual basis to provide as community benefits. As described in Section 4.4.2 of the RFP, at a minimum, Proposers should commit to setting aside $3,000 per MW, up to $200,000 per year, for community benefits.
- Detailing how community benefits funds will directly address needs in the host community to benefit community members.
- Explanation of community consultation and input collection process to define host community needs, along with community-supported actions and/or programs to address those needs.
    - If Proposers opt to work with a 501(c)(3) non-profit organization(s) to host and/or distribute community benefit funding, the names of the organization(s) must be provided with documentation 90 calendar days upon signing of the appropriate Stage 3 Contract.
- Any other community benefits (in addition to community funding) that will provide direct benefit to the Project's host community

Where to Find More Information

- Project website
- Proposer email and contact information

How to Provide Comments

Appendix B Attachment 6

DRAFT

REQUEST FOR PROPOSALS

FOR

RENEWABLE DISPATCHABLE GENERATION

AND

ENERGY STORAGE

O'AHU

DECEMBER 22, 2022

Docket No. 2017-0352

Appendix C – Code of Conduct Procedures Manual

I. INTRODUCTION

The Framework for Competitive Bidding ("Framework") adopted on December 8, 2006, by the Public Utilities Commission of the State of Hawaii (the "Commission") pursuant to Decision and Order No. 23121 (Docket No. 03-0372, Instituting a Proceeding to Investigate Competitive Bidding for New Generating Capacity in Hawaii) requires that the utility develop and follow a Code of Conduct whenever a utility or its affiliate seeks to advance a system resource proposal pursuant to a request for proposals ("RFP") issued by the Company. Section III.A.4 of the Framework required the utility to submit to the Commission for review and approval (subject to modification if necessary) a code of conduct prior to the commencement of any competitive bid process under the Framework. The proposed *Code of Conduct Pertaining to the Implementation of a Competitive Bidding Process the Stage 3 RFP* (the "Code of Conduct") requires the Company to also propose this *Code of Conduct Procedures Manual* (the "Procedures Manual") to implement the requirements of the Framework and the Code of Conduct.

This Procedures Manual has been developed to outline the procedures to be followed and the policies that have been developed surrounding the implementation of the Company's competitive bidding process for system resources. This Procedures Manual has been developed for the Company's Stage 3 RFP and in accordance with the requirements of Section IV.H.9.a(iii) of the Framework and outlines requirements (1), (3) and (4) of such section, namely: (1) the protocols for communicating with Proposers, the Hawaiian Electric Development Team, and others; (3) the documentation forms, including logs for any communications with proposers; and (4) other information consistent with the requirements of the solicitation process. Requirement (2) of the section, the evaluation process in detail and the methodologies for undertaking the evaluation process for the RFP are described in detail in the Stage 3 RFP. The bid evaluation process and methodology will consider both price/system impacts and non-price criteria in accordance with Section IV.E of the Framework and Tariff Rule 19.

The procedures and policies set forth herein have been designed to ensure that the procurement process is undertaken in a fair and equitable manner and that each Proposer is afforded an equal opportunity to participate and compete within the RFP requirements.

This Procedures Manual is intended to be followed by Company personnel in connection with implementing the Company's solicitation process and to manage communications between Company personnel and consultants participating in the RFP processes covered by the Framework. Necessary additions, deletions, and/or changes depending on the circumstances surrounding the RFP and directions from the IO may be required.

II. DEFINITIONS

- Affiliate – Any person or entity that possesses an "affiliated interest" in a utility as defined by section 269-19.5, Hawaii Revised Statutes ("HRS"), including a utility's parent holding company but excluding a utility's subsidiary or parent which is also a regulated utility.
- Affiliate Team – Employees and consultants of an Affiliate of the Company who prepare a proposal to be submitted to the Company in response to a Company RFP.
- ATRs – The Affiliate Transaction Requirements, issued by the Commission, applicable to the Companies and Affiliates, attached as Exhibit B to Order No. 36112 issued on January 24, 2019 in Docket No. 2018-0065.
- Code of Conduct – The *Code of Conduct Pertaining to the Implementation of a Competitive Bidding Process for the Stage 3 RFP* developed by Hawaiian Electric Company, Inc., Maui Electric Company, Ltd., and Hawai'i Electric Light Company, Inc. (each, a "Company" and collectively, the "Companies") to ensure the fairness and integrity of the competitive bidding process, in particular where the host utility or its affiliate seeks to advance its own system resource proposal in response to an RFP. The Code of Conduct follows the requirements described in Section IV.H.9.c of the Framework.

- Code of Conduct Acknowledgement – The Competitive Bidding Code of Conduct Acknowledgement of Receipt form acknowledging review of, and agreeing to abide by, the Code of Conduct and this Procedures Manual.
- Communications Log – A written record to note activities and/or information shared between the Company RFP Team or Hawaiian Electric Development Team with Shared Resources or Unassigned Company Resources, accessed via the RFP Communication Tool Kit SharePoint Site.
- Company Executive in Charge – The Company executive responsible for ensuring compliance with this Code of Conduct and serving as the point of contact for the Independent Observer for reporting any violations by the Company of the Code of Conduct. The Company Corporate Compliance Officer shall remain responsible for the Company's independent corporate code of conduct and may support compliance matters and questions arising with employees, agents and other representatives of the Company, e.g., conflicts of interest, with respect to this Code of Conduct.
- Company RFP Team – The Company personnel and outside consultants responsible for the development of the Company's RFP conducted under the Framework and the evaluation of bids submitted in response to this RFP. Subject to the transfer rules specified herein, the Company RFP Team will have fixed team members who will not have any involvement with the Hawaiian Electric Development Team for the subject RFP.
- Confidential Information – Any non-public information developed and provided by the Company (i.e., proprietary system information, etc.) or Proposers during the RFP process (such non-public information may include, for example, the identity of competing Proposers, and their technical, trade or financial information). This term includes any material non-public information regarding the RFP process developed for and used during the competitive bidding solicitation process, such as the evaluation process or criteria. Confidential Information does not include public information, such as information in the Company's public filings with the Commission.
- Director of Renewable Acquisition – The supervisor of the Division that will oversee the Company's competitive bidding process.
- Eligible Proposer – A Proposer who has met the minimum requirements and

threshold requirements in the RFP necessary to remain eligible to compete in the process.

- Energy Contract Manager – The staff position(s) within the Company's Renewable Acquisition Division responsible for managing the Company RFP Team. The Energy Contract Manager shall be a member of the Company RFP Team.
- Framework – The Framework for Competitive Bidding contained in Decision & Order No. 23121 issued by Commission on December 8, 2006, to establish rules for competitive bidding in response to a request for proposals when a utility seeks to acquire new system resources.
- Hawaiian Electric Development Team – The Company personnel and outside consultants responsible for the development of the Hawaiian Electric Development Team's responses to the RFP. Subject to the transfer rules specified herein, the Hawaiian Electric Development Team will have fixed team members who will not have any involvement with the Company RFP Team for this RFP.
- Independent Observer ("IO") – The neutral person or entity appointed by either the Commission or utility to monitor the utility's competitive bidding process, and to advise the utility and Commission on matters arising out of the competitive bidding process, as described in Part III.C of the Framework.
- Manager of Energy Procurement – The supervisor of the department within the Company's Renewable Acquisition Division responsible for directing the resources responsible for the implementation of the competitive bidding process pursuant to the Framework. The Manager of Energy Procurement will report to the Director of Renewable Acquisition on the status of the competitive bidding process and shall be a member of the Company RFP Team.
- Non-Price Evaluation Team – Employees and consultants of the Company who evaluate the Proposal non-price related criteria as set forth in the RFP. Non-Price Evaluation Team members will not include any Shared Resources and will be solely made up of Company RFP Team Members.
- Price Evaluation Team – Employees and consultants of the Company who evaluate the Proposal price related criteria set forth in the RFP. Price Evaluation Team members will not include any Shared Resources and will be solely made up of Company RFP Team Members.
- Proposer – Entity who submits or plans to submit a proposal in response to a

Company-issued RFP. An Affiliate of the Company or a Hawaiian Electric Development Team participating in the RFP and submitting a proposal shall be considered a Proposer.

- RFP – A written request for proposals issued by the Company to publicly solicit bids to supply future system resources to the Company pursuant to the competitive bidding process established in the Framework.
- Roster – A consolidated list of members that comprise the Company RFP Team, Hawaiian Electric Development Team, Shared Resources and Unassigned Company Resources located in the RFP Communication Tool Kit SharePoint Site. Names and roles of Company employee and consultants will be identified.
- Shared Resource – Company employees and consultants who, because of the scarcity of their expertise within the Company, are designated and authorized to provide information or input to both the Company RFP Team and the Hawaiian Electric Development Team (but not any Affiliate Team) and is not a resource dedicated to either team. For example, Shared Resources may include an environmental attorney and members of the Company's Risk Management Department.
- Unassigned Company Resource – Company employees unassigned to an essential team that may be called upon by the Company RFP Team and/or the Hawaiian Electric Development Team (but not any Affiliate Team) to assist in meeting unforeseen tasks for the RFP or the Hawaiian Electric proposal. For example, the Company RFP Team may be unable to evaluate an unforeseen technical specification included in a bid. In that event, the Company RFP team would need to request assistance from a Company employee or a consultant that is not already assigned to an essential team and possesses the specific expertise. Such personnel are intended to assist the requesting team only in an ad hoc manner, limited in scope and purpose to the particular task required.

III. STATEMENT OF OBJECTIVES

The Code of Conduct and this Procedures Manual address (1) communication requirements and procedures associated with the relationship between utility employees (Company RFP Team, Hawaiian Electric Development Team, Shared Resources and

Unassigned Company Resources); (2) communication requirements and procedures associated with the relationship between the Company RFP Team, the Hawaiian Electric Development Team and Proposers; and (3) communication requirements associated with the relationship between Company management and the Company RFP Team.

The Code of Conduct and this Procedures Manual also include procedures for the sharing of resources, where appropriate, by the Company RFP Team and the Hawaiian Electric Development Team for the purposes of completing their efforts to effectively evaluate the RFP or to submit a bid in response to the RFP. The small size of the Company and limitation of resources will require specialized services, information exchange and sharing of resources in certain limited circumstances. Company personnel and consultants identified as "Shared Resources" shall be designated by the Company for this specific purpose.

IV. ORGANIZATION AND COMMUNICATION RESPONSIBILITIES

This section outlines the RFP organizational structure for the development of the RFP and the Hawaiian Electric Development Team options and the organization's responsibilities to ensure that communications between Company personnel and consultants working on their respective RFPs or Hawaiian Electric Development Team projects are conducted in a fair, consistent, and equitable basis so that the Hawaiian Electric Development Team does not enjoy any unfair advantage over other Proposers responding to an RFP.

A. Organization

The Company shall identify and maintain two separate teams to facilitate the independence and objectivity of the Company resources working on the RFP and ensure an arms-length relationship with the resources working on the Hawaiian Electric Development Team's project to avoid any real or perceived inequity in the RFP process. The two essential teams shall be the "Company RFP Team" and the "Hawaiian Electric Development Team."

Other limited Company resources, such as select staff from various functional areas of the Company that are in short supply and thus cannot be dedicated solely to either team, may be designated as "Shared Resources" to perform services for the Company RFP Team and Hawaiian Electric Development Team. Shared Resource employees are allowed to carry on with both their RFP (for either the Company RFP Team and/or the Hawaiian Electric Development Team) and regular functions throughout the resource planning process (including the development of any Company Parallel or Contingency Plan as defined in the Framework), which may require communications with or services performed for the Hawaiian Electric Development Team. Shared Resource employees, however, will not participate in the evaluation and selection process of proposals submitted in response to the RFP. Rules for communications between Shared Resources and the essential teams are specified below.

Company employees unassigned to the RFP may be called upon by the Company RFP Team, Hawaiian Electric Development Team, or both for help to meet unforeseen tasks. After completing the Code of Conduct training, these "Unassigned Company Resources" are eligible to assist on an ad hoc basis with the requirement that all communications as an Unassigned Company Resource must be memorialized and logged in the same manner as communications with Shared Resources on the Communication Log. If an Unassigned Company Resource is called upon repeatedly for a substantial amount of assistance by a particular team, the employee should be assigned to such team or evaluated for designation as a shared resource.

B. Essential Teams

1. Company RFP Team. The Company RFP Team, tasked with preparing the RFP and evaluating the responses and bids in response to the RFP, will be led by a Director/Manager level employee and consist primarily of experienced employees together with possible outside consultants, with backgrounds in a number of disciplines necessary to conduct a thorough evaluation of each proposal. The Company RFP Team will be comprised of a Price Evaluation Team and a Non-Price Evaluation Team and will be prepared to evaluate proposals on the basis of their price and non-price aspects pertaining to their level of expertise. Members of the Company RFP Team will include

professionals with experience in the following areas of expertise: engineering, siting/land use, environmental, transmission planning, fuel procurement, legal, financial planning, system operations, integrated resource planning, generation planning, production cost analysis, and others as needed.

The Price Evaluation Team and the Non-Price Evaluation Team will conduct their sections of the bid evaluation process separately and will not share the results of their evaluation with members of the other sub-team. Each team will submit their evaluation results to an oversight team, which will be responsible for compiling the results of the evaluations and selecting the Priority List.

The Energy Contract Manager will be responsible for directing the evaluation efforts of the Company RFP Team when the proposals are received. The Energy Contract Manager will be responsible for maintaining the documentation underlying the evaluation of each proposal as well as all communications with Proposers.

2. The Hawaiian Electric Development Team. The Hawaiian Electric Development Team, tasked with preparing any Company proposal to be submitted by the Company in response to the Company RFP, will consist primarily of Company employees, along with possible outside consultants with backgrounds in a number of disciplines necessary to complete a competitive proposal in response to the Company RFP. The members of the team will include professionals with experience in the following areas of expertise: engineering, siting/land use, environmental, transmission planning, fuel procurement, legal, financial planning, system operations, integrated resource planning, generation planning, production cost analysis, and others as needed.

3. Affiliate Team. Any Affiliate Team will be comprised solely of employees and consultants of the Affiliate and no Company employee or consultant shall serve as a member of an Affiliate Team; provided, however, that a consultant may perform services for an Affiliate and the Company so long as appropriate "walls" are established satisfactory to the Company that ensures that employees of the consultant working for the Affiliate Team do not also perform work for the Company nor communicate with employees of the consultant performing work for the Company, and vice versa. The

Company will inform consultants providing services for the Company RFP Team of these separation requirements, and will seek confirmation in writing from any consultant performing services for an Affiliate and the Company that such separation requirements will be met. Affiliate Teams will be considered and treated as separate independent third-party Proposers for all purposes within the RFP and shall have no access to, interaction or communications with Shared Resources or Unassigned Company Resources for the purpose of completing a proposal in response to the RFP. Affiliate Teams shall also be subject at all times to the terms, conditions and restrictions specified in the Company's ATRs.

4. Transfers between Teams. As members of both the Company RFP Team and the Hawaiian Electric Development Team are intended to be fixed, transfers between teams should not be permitted. However, there will be instances where a member of a particular team (whether Company RFP or Hawaiian Electric Development) transfers to a position in which he/she may be requested, as part of his/her new job responsibilities, to participate as a member of the other team. Such employee shall not be permitted to transfer from one team to the other during the pendency of any stage or phase of the RFP. After completion of a stage or phase of the RFP under which the employee recently participated, the employee may transfer to the other team under the following conditions: (a) the employee is prohibited from disclosing any Confidential Information known to such employee as a result of being a member of his/her former team with members of the new team he/she is joining; and (b) for a period of one (1) year, such employee shall not: (a) participate or be involved in establishing the evaluation criteria and the evaluation of any subsequent stage(s) or phase(s) of the RFP which such employee participated in with his/her former team; or (b) participate or be involved in the formulation and/or origination of a proposal for any subsequent stage(s) or phase(s) of the RFP which such employee participated in with his/her former team.

Transfers of employees between the Company and any Affiliate and their subsequent work on RFPs shall be subject to the terms, conditions and restrictions specified in the ATRs.

C. Communications Protocols

1. Overview and General Requirements.

The Company has developed policies and procedures governing communication between the Company RFP Team, the Hawaiian Electric Development Team, Shared Resources, the Proposers, the IO, and with the Commission regarding RFP design and bid evaluation. Bid information and evaluation data and information shall not be communicated between members of the Company RFP Team, outside parties and other employees within the Company except to those with a business need to know.

To ensure that the competitive bidding process is fair and unbiased, that all Proposers have access to the same information so that no Proposer has an unfair advantage, and that any Hawaiian Electric and/or Affiliate proposals do not have any unfair competitive advantage over third-party bids, the Company shall follow the Code of Conduct whenever the utility or its Affiliate is seeking to advance a resource proposal as provided in Section IV.H.9.b of the Framework.

Each employee or consultant on the Company RFP Team, Hawaiian Electric Development Team and Shared Resources shall read, acknowledge and sign the Code of Conduct Acknowledgement. Unassigned Company Resources who are called upon by the Company RFP Team or Hawaiian Electric Development Team for help to meet unforeseen tasks shall also read, acknowledge and sign the Code of Conduct Acknowledgement.

The Company issuing the RFP will establish a shared drive on its corporate computer network designed to maintain the bid evaluation documentation and other information associated with the bidding process. Only Company RFP Team members will have access to all the files on the shared drive.

In cases where staffing and resources are limited or constrained, the Company may identify Shared Resources or those employees eligible to provide information or serve as a resource to both the Company RFP Team and the Hawaiian Electric Development Team. Specific rules to log communications with the Company RFP Team or the Hawaiian Electric Development Team are described below.

Shared Resources will not have access to the Company's shared drive established for the RFP process which will include the documentation of the bid evaluation results.

Team members should clearly mark all e-mails, documents, or other communications that contain Confidential Information and make clear which team should not receive it with the following header or a substantially similar message: "This communication contains Hawaiian Electric Development Team information that must be kept confidential. DO NOT copy, forward, or discuss the contents with Company RFP Team members" OR "This communication contains Company RFP Team information that must be kept confidential. DO NOT copy, forward, or discuss the contents with Hawaiian Electric Development Team members."

2. Communications Between the Company RFP Team and Proposers, including the Hawaiian Electric Development Team and any Affiliate Team.

During the RFP process, the Energy Contract Manager shall serve as the primary contact person for all RFP communications with Proposers. This is important from the standpoint of maintaining consistency and confidentiality of information between Proposers and the Company. For documentation and oversight purposes, all communications from Proposers must be submitted via the communication means specified in the RFP (e.g., specified website link provided by the Company (the "Company RFP website"), specified RFP electronic procurement platform, and/or specified RFP electronic mail address ("email")). The IO will monitor all communications through any communication means specified in the RFP. To ensure fair and equal access to information, any Hawaiian Electric Development Team and/or Affiliate Team shall be considered a Proposer for communication purposes and any request for information from the Hawaiian Electric Development Team or Affiliate Team to the Company RFP Team shall be through the communication means specified in the RFP.

Subject to confidentiality obligations, it is the objective of the Code of Conduct that all Proposers, including the Hawaiian Electric Development Team and any Affiliate Team, receive access to information released by the Company RFP Team, whether in response to a question from a Proposer or not, at the same time.

The communications process for addressing questions and requests for information from Proposers, and for the Company RFP Team to provide information to Proposers, is provided below:

a. Other than during Company sponsored conferences, Proposers must submit all questions to the Company via the communication means specified in the RFP.

b. Questions will be reviewed and responses will be coordinated with the appropriate functional area within the Company for a response. Every reasonable effort will be made to provide responses in a timely manner.

c. All responses, including the classification of such response, i.e., whether non-confidential or confidential as described below, will be made available to the IO for monitoring purposes. The IO may choose to comment on any response at its discretion.

d. Depending on the questions received, responses may involve Confidential Information of the Company and/or Proposers. Release of any Company Confidential Information must be approved in advance by the Company executive authorized to release the Confidential Information. Any release of Company Confidential Information shall be accompanied by appropriate confidentiality and non-disclosure agreements, protective orders or other means required to maintain the confidentiality of the Company Confidential Information while still permitting its disclosure under circumstances deemed appropriate by the responsible Company executive. Other non-Company Confidential Information will not be shared without the prior written consent of the owner of such Confidential Information and the execution of appropriate confidentiality and non-disclosure agreements by all recipients of such Confidential Information. Responses will be categorized as follows:

i. <u>Non-Confidential Responses</u>: Questions and responses will either be posted directly on the Company RFP website (process-related questions or simple, non-substantive information) or a description of the information that can be made available will be posted and Proposers will be instructed to submit a request to the Company via the communication means specified in the RFP to receive a copy.

ii. <u>Confidential Responses</u>: Questions and a description or notice of a Confidential Information response will be posted on the Company RFP website and Proposers will be instructed to submit a request to the Company via the communication means specified in the RFP to receive instructions on how to access the Confidential Information. The Confidential Information will only be provided to the requestor after receipt of an executed confidentiality and non- disclosure agreement. Only those who have qualified to submit a bid (i.e., Eligible Proposers) and have executed a confidentiality and non-disclosure agreement will be considered for receipt of Confidential Information.

iii. <u>Process for Distribution of Confidential Information</u>: Confidential Information provided in response to questions from proposers may be made available only to parties as indicated above via the following:

A. <u>Confidential Information that is approved for exchanging on a secured access site</u>: (1) Confidential Information may be made available on a secured website with an individual password provided to each approved

Proposer; and (2) Confidential Information in documents may be transmitted to approved recipients through the Company's secure email system.

B. Confidential Information that can be made available for inspection only, but cannot be copied: There may be some types of Confidential Information that the Company may consider making available for inspection only with no copies allowed. This type of Confidential Information will be made available on Company premises for inspection only. Proposers will be advised via the communication means specified in the RFP to make arrangements with Company staff to view the Confidential Information.

C. Confidential Information that may not be released: In the event that Proposers submit questions that require responses that the Company feels are not appropriate to provide for reasons which may include, but not be limited to, safety, security, protection of trade secrets or intellectual property rights, Proposers will be advised as such via the communication means specified in the RFP.

e. Prior to and during the RFP, developers may direct questions to the Company prior to submitting a Proposal to discuss specific questions regarding their specific Proposal. Questions shall be directed to the communication means specified in the RFP. Questions and responses that do not contain Confidential Information and which are deemed relevant to all Proposers will be published without identifying information via the Company RFP website.

f. Once bids are received, the Company may submit information requests to Proposers to clarify their proposals or request additional information. All contacts with Proposers will be through the communication means specified in the RFP. All contacts and information exchanged will be under the oversight of the IO.

g. A single exception to the communication process outlined above shall be instituted for the purpose of facilitating the verification of proposed project models and documentation required to perform the IRS. For this limited scope, the Company's Manager of Interconnection Services will serve as the primary contact person for all such interconnection communications with the Proposers on the Priority List, provided that all necessary confidentiality and non-disclosure agreements are in place. The Manager of Interconnection Services and personnel in the Interconnection Services Department shall be members of the Company RFP Team. Interconnection communications will be limited to a Proposer's bid and no more information other than as necessary to facilitate such communications will be permitted. Discussion of locations of proposed projects shall be limited to that necessary only to determine the interconnection requirements of such project. The IO shall have the right to monitor all such communications in his/her discretion.

3. Communications Between the Company and the Commission.

The Company's Regulatory Affairs staff will be responsible for initiating communication with the Commission regarding the RFP or the Company's evaluation process. Regular updates may be provided to the Commission regarding the RFP process if requested.

4. Communications Between the Company RFP Team and the IO.

Communications between the Company RFP Team and the IO will be required for many aspects of the evaluation process. The IO is also required to maintain confidentiality of any Confidential Information. The IO will coordinate all activities through the Energy Contract Manager. The IO will be invited to participate in any meetings or discussions between the Company RFP Team and the Proposers and other communications as noted above. Sufficient notice will be provided whenever possible and teleconference and/or web conference alternatives may be utilized.

5. Communications Between the Company RFP Team and the Hawaiian Electric Development Team or any Affiliate Team.

Any communication between the Company RFP Team and the Hawaiian Electric Development Team or any Affiliate Team with respect to the RFP shall be handled no differently than with Proposers and other outside parties. Accordingly, the Hawaiian Electric Development Team or any Affiliate Team will be required to submit any questions or information requests to the Company RFP Team via the communication method specified in the RFP and all responses will be provided in the same manner as to other Proposers. Accordingly, as stated in Section 2 above, responses will be provided to the IO for monitoring purposes via email or the PowerAdvocate messaging system. Members of the Company RFP Team are prohibited from providing any input into the development of a proposal by the Hawaiian Electric Development Team or an Affiliate. Company RFP Team members are prohibited from sharing any Confidential Information (i.e., detailed evaluation criteria, other proposals, etc.) with any Hawaiian Electric Development or Affiliate Teams except in accordance with the procedures in the Code of Conduct, this Manual or the RFP.

Company RFP Team members and Hawaiian Electric Development Team members may continue to work with each other on projects not related to the RFP. Further, members of each respective team do not have to be physically separated from each other, but members of each team must make reasonable efforts to keep all Confidential Information (including electronic data) secure and inaccessible to the other team.

Company RFP Team members and Affiliate Team members may continue to work with each other on matters not related to the RFP as permitted under the ATRs.

6. Communications among the Company RFP Team, the Hawaiian Electric Development Team and Shared Resources.

Shared Resources may provide services to the Company RFP Team and the Hawaiian Electric Development Team (but not any Affiliate Team). Shared Resources shall be limited as much as possible to instances where Company resources cannot provide a dedicated member to the Company RFP Team and the Hawaiian Electric Development Team at the same time and still provide the necessary functions of its area to the Company as a whole. Shared Resources are expressly prohibited from providing any information developed on behalf of the Company RFP Team to the Hawaiian Electric Development Team or any information developed on behalf of the Hawaiian Electric Development Team with the Company RFP Team, except through the formal communication process outlined above, i.e., through the communication means specified in the RFP.

Additionally, a written record of the time, date and substance of all conversations, data and written material directly or indirectly exchanged with the Company RFP Team or the Hawaiian Electric Development Team that pertain to the RFP shall be maintained on the Communications Log. The RFP Communication Tool Kit SharePoint Site will be set up and managed by the Energy Contract Manager to provide an easy to use and understand mechanism to log and memorialize these conversations.

Shared Resources will not have direct access to the Company's shared drive developed for the RFP process which will include documentation of the bid evaluation results.

7. Communications between the Company RFP Team, the

Hawaiian Electric Development Team and any Unassigned Company Resource or consultant that is not a Shared Resource.

There may be times where a Company RFP or Hawaiian Electric Development Team (but not an Affiliate Team) member may need ancillary or other ministerial or administrative assistance that requires communication and/or assistance from Company personnel who are neither on any team nor considered a Shared Resource. Under those circumstances, such personnel may assist the requesting team member on an ad hoc basis upon the following conditions:

a. The essential team member making the request must inform the Company personnel that sharing of the requested information or assistance with the other team, be it the Company RFP or Hawaiian Electric Development Team, is expressly prohibited under the Code of Conduct.

b. The assisting Company personnel shall complete the Code of Conduct training and sign the Code of Conduct Acknowledgement.

c. The assisting Company personnel shall be directed to the Roster provided by such requesting team member to determine and/or confirm the restrictions on communication with the other team members. The essential team member making the request will ensure the Roster is updated by the Energy Contract Manager to include the assisting Company personnel.

d. A written record of the time, date and substance of all conversations, data and written material directly or indirectly exchanged with the Company RFP Team or the Hawaiian Electric Development Team that pertain to the RFP shall be maintained on the Communication Log. The RFP Communication Tool Kit SharePoint Site will be set up and managed by the Energy Contract Manager to provide an easy to use and understand mechanism to log and memorialize these conversations.

e. If assistance from an Unassigned Company Resource becomes more than occasional or more substantive than ancillary, ministerial or administrative services, the Unassigned Company Resource should be considered for inclusion on the team that he/she has been assisting on such basis. Additionally, the Unassigned Company Resource may also be considered for inclusion as a Shared Resource. Members of the Company RFP Team and/or Hawaiian Electric Development Team shall consult with the Company executive for resolution.

8. Communications between the Company RFP Team, the Hawaiian Electric Development Team and Company Management.

The Company RFP Team and the Hawaiian Electric Development Team will necessarily require management approval of the RFP and the Hawaiian Electric proposal. Because of the size of the Company, it may be possible that a single employee (at whatever level) (the "Approver") may have approval responsibility for matters affecting the RFP and the Hawaiian Electric proposal. Approvers in this situation must use their best judgment in making decisions reviewing and approving matters for the respective teams. The Code of Conduct must be adhered to in these situations and the Approver must not communicate matters learned from the Company RFP Team with the Hawaiian Electric Development Team.

If an Approver feels that he/she cannot manage this potential conflict, the Approver is recommended to consult with his/her immediate supervisor to determine whether such higher authority could be appointed with the task of reviewing and approving matters for a designated team, either the Company RFP Team or the Hawaiian Electric Development Team. In matters where a team of employees (including one or more Approvers) is responsible for reviewing and approving matters for the respective teams, approving employees (from whatever level, including executives) with information from reporting personnel beneath them from both the Company RFP Team and the Hawaiian Electric Development Team may consider recusing himself/herself from the decision making if such employee cannot objectively make a decision on the matter.

Finally, an Approver may be a member of the Company RFP Team and have a subordinate reporting to him/her that is a member of the Hawaiian Electric Development Team (or vice versa). In such situations, because the Code of Conduct prohibits communication between the teams, the Approver must recuse himself/herself from the decision making and request his/her manager to review and approve the matter in his/her place.

In all instances, it is possible that any particular situation above may be addressed and/or resolved by the terms and conditions of the Company's internal code of conduct implemented for all employees and consultants of the Company. As appropriate, an Approver or any other team member, Energy Contract Manager or Company executive in Charge may involve the Company's Corporate Compliance Officer for input and possible resolution under the Company's internal corporate code of conduct.

V. WHEN THE CODE OF CONDUCT BECOMES EFFECTIVE

A. Prior to development of the requirements for the RFP, the Code of Conduct for the RFP will be activated. However, if the Hawaiian Electric Development Team determines at any time that it will not pursue a Hawaiian Electric Development Team option for a particular RFP, the Code of Conduct may be de-activated.

B. Upon the activation of the Code of Conduct, members of the Company RFP Team and the Hawaiian Electric Development Team must then conduct activities on the RFP or Hawaiian Electric proposal process in compliance with the Code of Conduct. Once identified and having commenced work, no information may be shared outside the respective team members with respect to the RFP or a Hawaiian Electric proposal except through the formal communication processes outlined above.

C. Immediately upon assignment to a Company team (RFP Team or Hawaiian Electric Development Team), designation as a Shared Resource, or request to assist as an Unassigned Company Resource, each such employee or consultant must review this

Manual, and sign the Code of Conduct Acknowledgement.

D. Within the RFP process, after a member has been assigned to a particular Company team (RFP Team or Hawaiian Electric Development Team), he or she will not be able to transfer to the other Company team during the pendency of any particular stage or phase of a particular RFP. Transfers of members of any particular team to another team after the RFP, or a particular stage of phase of the RFP, is completed shall be governed by the transfer rules specified herein. It is the responsibility of each team to fill vacant team positions with employees that have not been previously assigned as a team member for a team until the RFP, or the particular stage or phase of the RFP, has been completed.

E. Each employee and consultant working on the RFP shall review the Code of Conduct and sign the Code of Conduct Acknowledgement attesting to his/her compliance with the Code of Conduct until the employee is no longer working in the position he/she was in while working on the RFP.

F. The Energy Contract Manager will be responsible for maintaining the Roster and the signed Code of Conduct Acknowledgements. The Company Executive in Charge shall be responsible for ensuring compliance with the Code of Conduct and shall have the written authority and obligation to enforce the Code of Conduct.

VI. IMMEDIATE ACTIONS UPON ACTIVATION OF THE CODE OF CONDUCT

The following items are required to be completed as soon as possible after activation of the Code of Conduct, but no later than the designated events specified for each item below.

A. Prior to development of the requirements for the RFP, a Roster listing employees and consultants in their role; Company RFP Team, Hawaiian Electric Development Team, Shared Resource or Unassigned Company Resource will be generated. When the IO is appointed, this Roster shall be provided to him/her. The Roster shall be placed in the RFP Communication Tool Kit SharePoint Site so that any

Company personnel can access the database to determine the identity of the respective teams and Shared Resources.

B. Upon the finalization of the Roster for the RFP, the Energy Contract Manager shall verify that all employees (whether full-time, part-time, temporary, or contract) and consultants involved in the competitive bidding process, such as members of the Company RFP Team, the Hawaiian Electric Development Team, Shared Resources or Unassigned Company Resources, have acknowledged receipt of the Code of Conduct and his or her responsibility to comply with the Code of Conduct by submitting the Code of Conduct Acknowledgement (with electronic acknowledgment being acceptable). If an employee or consultant is later added to a team, the Energy Contract Manager shall also verify that such employee or consultant has submitted the Code of Conduct Acknowledgment.

C. Prior to any solicitation for comments or questions to the RFP, establishment of the Company email address to accept requests for information from Proposers, including the Hawaiian Electric Development Team or any Affiliate Team.

D. Prior to the drafting of any documents for any particular RFP, establishment of the Company-secured site that houses the accessible database (such as SharePoint).

VII. WHEN THE CODE OF CONDUCT TERMINATES

A. The Code of Conduct for the RFP will terminate after the following two conditions are met when:

- the final contract(s) for the RFP conducted under the Framework with the successful proposer(s) is/are executed, or when written notice of termination of the RFP to be conducted under the Framework is provided by the Manager of Energy Procurement or his/her designee to the IO and the Commission, and
- a certification of Code of Conduct compliance by all employees participating in the RFP process is submitted by affidavit by the Company Executive in Charge.

VIII. DOCUMENTATION FORMS

The following documentation forms may be utilized by those Company personnel involved in the RFP. These forms may be amended from time to time as necessary. Additional forms may also be developed as determined necessary.

- Code of Conduct Acknowledgement
- Communications Log
- Roster

IX. APPLICABILITY OF THE ATRs

Except as specifically made applicable under Section V.C.1.i of the ATRs with respect to wholesale power procurement from Affiliates, the ATRs shall not apply to RFP matters covered by the Framework, the Code of Conduct and this Procedures Manual as it relates to the Company's interactions between the Company RFP Teams and Affiliate Teams. Reference to the ATRs in the Code of Conduct and/or this Manual are specifically for matters outside the Company's administration of the RFP; provided, however, that such applicability may be revised as necessary and as may be directed by the Commission for any RFP.[1]

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[1] See Decision and Order No. 35962, filed on December 19, 2018, in Docket 2018-0065, at 56-57.

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REQUEST FOR PROPOSALS

FOR

RENEWABLE DISPATCHABLE GENERATION

AND

ENERGY STORAGE

O'AHU

DECEMBER 22, 2022

Docket No. 2017-0352

Appendix D – PowerAdvocate User Information

Hawaiian Electric

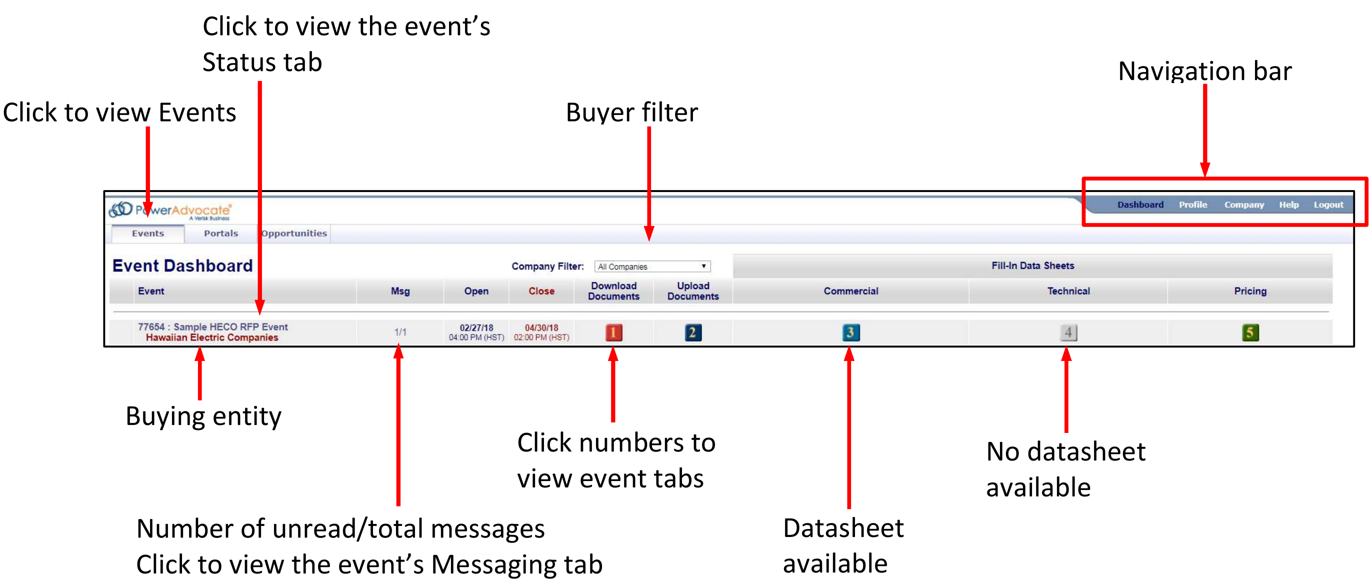
Sourcing Intelligence Quick Start for Suppliers

Logging In

1. Launch a web browser and go to www.poweradvocate.com
2. Click the orange **Login** button.
3. Enter your account **User Name** and **Password** (both are case-sensitive) and click **Login.**
4. Click the **Events** tab if it is not already displayed.

Dashboard

Your Dashboard lists the events you have been invited to. A line divides currently accessible events from others.



- Click an event name to view its Status tab, which displays a summary of your activity and key event dates. To view specific details of an event, click the buttons 1-5 to view the corresponding tab.
- To return to the Dashboard, click **Dashboard** in the navigation bar at the top of the window.
- An event will not appear on your Dashboard until you have been added as a participant.

Downloading Bid Packages

All of the Buyer's bid package documents (if any) are centrally stored on the PowerAdvocate Platform. To view bid documents, click "1" on your Dashboard or on the **1. Download Documents** tab from within the event.

- You can access the **Bid** sub-tab after the event opens. You can access Buyer documents before the event is opened from the **Pre-Bid** sub-tab, if the Buyer utilizes this feature.
- To view or download a document, click the file name.
- To download multiple documents:
    1. Select the checkbox in the Download column for each document you wish to download or click **Select All**.
    2. Click **Download Selected Files**.

Uploading Documents

To upload your documents, click "2" on your Dashboard, or on the **2. Upload Documents** tab from within the event.

- Do not upload any files to the Pre-Bid tab.
- To upload a document to the Bid tab:
    1. Specify a **Document Type** (Reference ID can be left blank).
    2. Click **Choose File**, navigate to and select the document, and then click Open; multiple files can also be compressed into one .zip file for upload.
    3. Click **Submit Document**.

Datasheets

Datasheets (3. Commercial Data, 4. Technical Data, 5. Pricing Data) will not be used in this RFP event. All Proposal information will be uploaded for submission through the 2. Upload Documents tab. Buttons/tabs are grayed out if the event is not using a particular type of datasheet.

Communicating with the Bid Event Coordinator/Company Contact

Suppliers should use Email to contact the Bid Event Coordinator/Company Contact while the bid event is open. In this RFP, PowerAdvocate Messaging will not be used.

Getting More Information

- Click **Help** on the navigation bar to display online help.

- Supplier documentation can be downloaded from the online help system.
- Call PowerAdvocate Support at 857-453-5800 (Mon-Fri, 8 a.m. to 8 p.m. Eastern Time) or e-mail support@poweradvocate.com.
- PowerAdvocate is now part of Wood Mackenzie.

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REQUEST FOR PROPOSALS

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AND

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Docket No. 2017-0352

Appendix E – Mutual Confidentiality and Non-Disclosure Agreement

Hawaiian Electric

APPENDIX E
MUTUAL CONFIDENTIALITY AND NON-DISCLOSURE AGREEMENT
Independent Power Producers – ("IPPs")

This Mutual Confidentiality and Non-Disclosure Agreement (this "Agreement") is effective as of ________________, 20____ (the "Effective Date") between [INSERT NAME OF IPP], a [State of incorporation/organization] [type of entity] ("IPP") and Hawaiian Electric Company, Inc., a Hawaiʻi corporation (the "Company"). In consideration of the mutual promises contained in this Agreement, including the provision of Confidential Information (as defined below) by either party to the other hereunder, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

1. Background

The Companies have or intend to issue a Request for Proposals ("RFP") for renewable energy generation and/or storage projects. The IPP has or intends to submit one or more proposals in response to this RFP ("Proposal").

In connection with the IPP's proposed project, the Companies may conduct an interconnection requirements study ("IRS") to establish the requirements for interconnection of the IPP's proposed project to the Companies' electric grid. The RFP process may also result in the award of a potential power purchase agreement, the terms of which must be agreed upon by the parties ("PPA Negotiations"). For purposes of this Agreement the term "Project" refers to the RFP, Proposal, potential IRS and PPA Negotiations.

In order to evaluate the Project, either party may from time to time provide to the other party certain Confidential Information. The parties are willing to provide such Confidential Information to each other upon the terms and conditions of this Agreement.

2. Confidential Information

Except as set forth in Section 3 (Exclusions from Confidential Information) below, "Confidential Information" means all non-public, confidential or proprietary information disclosed by either party (the "Provider") to the other party (a "Recipient") its affiliates and its and their directors, officers, employees, agents, advisors, consultants, contractors, financing parties and investors (including, without limitation, financial advisors, counsel and accountants) and controlling entities or individuals (collectively, "Representatives") whether disclosed orally or disclosed or accessed in written, electronic or other form of media, and whether or not marked or otherwise identified as "confidential," including, without limitation:

(a) all information concerning the Provider and its affiliates', and their customers', contractors', suppliers', financing parties', investors' and other third parties' past, present and future business affairs including, without limitation, finances, customer information, supplier information, pricing and cost information, products, services, designs, processes, organizational structure and internal practices, forecasts, sales and other financial results, records and budgets, business, marketing, development, sales, other commercial information and strategies, and negotiating positions and drafts made or exchanged between IPP and the Companies during negotiations or other discussions prior to such negotiated documents or agreements becoming public;

(b) all "Personally Identifiable Information," which shall include all information belonging to an individual that may be used to track, locate, or identify such individual, or which is otherwise protected by privacy laws, including but not limited to IP address, residential address, personal telephone number, social security number, date of birth, government-issued identification number, financial account number, personal email address, and username or password, all of which shall always be considered and deemed to be Confidential Information whether marked as "confidential" or not;

(c) all "Critical Infrastructure Confidential Information" concerning the Companies' generation, transmission, and distribution systems or its information technology or security systems, including but not limited to all designs, specifications, components, source code, object code, images, icons, audiovisual components and objects, schematics, drawings, protocols, processes, and other visual depictions, in whole or in part, of any of the foregoing, all of which shall always be considered and deemed to be Confidential Information whether marked as "confidential" or not;

(d) the Provider's unpatented inventions (whether or not they are patentable), ideas, methods and discoveries, techniques, formulations, development plans, trade secrets, know-how, unpublished patent applications and other confidential intellectual property;

(e) all previously disclosed information designated as or deemed to be "Confidential Information" under previous nondisclosure and confidentiality agreements executed between the parties, whether expired or still in effect, it being the understanding of the parties that any/all such agreement(s) be deemed superseded by this Agreement and that all Confidential Information exchanged between the parties to date shall be henceforth governed by this Agreement;

(f) any third-party confidential information included with, or incorporated in, any information provided by the Provider to the Recipient or its Representatives, including source code of any of Provider's vendors or suppliers; and

(g) all notes, analyses, compilations, reports, forecasts, studies, samples, data, statistics, summaries, interpretations and other materials ("Notes") prepared by or for the Recipient or its Representatives that contain, are based on, or otherwise reflect or are derived from, in whole or in part, any of the foregoing.

IPP and the Companies understand that in the course of obtaining approval of the Project, any documents filed with the State of Hawaiʻi Public Utilities Commission ("Commission") may be considered government records subject to the Uniform Information Practices Act ("UIPA"), Hawaiʻi Revised Statutes ("HRS") Chapter 92F.

All written Confidential Information provided to the Companies by IPP and marked as "confidential" in response to a request by the Companies for purposes of filing such information with the Commission shall be accompanied in writing by (1) a clear statement of the basis for its confidential status, including the applicability of any UIPA exceptions under HRS § 92-13, (2) a description, with particularity, of the cognizable harm to IPP if such information were to be disclosed publicly, and (3) if applicable, any additional justification or harm to IPP were the Confidential Information to be disclosed to other parties or participants in the subject Commission proceeding (collectively, the "Justification"). IPP expressly allows the Companies to disclose or otherwise use the Justification in order to justify withholding the Confidential Information from public disclosure in accordance with this Agreement, including without limitation, filing of the information in a Commission proceeding pursuant to Section 4(e) below and, to the extent necessary, any required disclosure pursuant to Section 5 (Required Disclosure and Notice) below. The IPP will provide the Companies with such Justification within three (3) business days of the Companies' written request for such Justification, provided that if the Companies are given less than five (5) business days by the Commission to produce the Justification, then the IPP will provide the Companies with the Justification not less than 24 hours before the Companies' due date for such Justification, provided that (1) the Companies provides the IPP with the request as soon as reasonably practicable and (2) to the extent possible, IPP shall be given at least one full business day to provide the Justification.

A Provider shall be permitted to designate as "confidential" information previously provided to Recipient at which point such information shall become and be deemed to be Confidential Information under this Agreement, provided that such information is not specifically excluded under Section 3 (Exclusions from Confidential Information) below. Notwithstanding anything to the contrary stated herein, any "Confidential Information" previously provided by IPP under any previously executed nondisclosure and confidentiality agreement shall not require a Justification unless such is requested by the Companies in connection with a required or anticipated disclosure described herein.

3. Exclusions from Confidential Information

Except as required by applicable federal, state, or local law or regulation, the term "Confidential Information" as used in this Agreement shall not include information that:

(a) at the time of disclosure is, or thereafter becomes, generally available to and known by the public other than as a result of, directly or indirectly, any violation of this Agreement by the Recipient or any of its Representatives; provided, however, that Confidential Information shall not be disqualified as Confidential Information (i) merely because it is embraced by more general or generic information which is in the public domain or available from a third party, or (ii) if it can only be reconstructed from information taken from multiple sources, none of which individually shows the whole combination (with matching degrees of specificity);

(b) at the time of disclosure is, or thereafter becomes, available to the Recipient on a non-confidential basis from a third-party source, provided that such third party is not and was not prohibited from disclosing such Confidential Information to the Recipient by a contractual or other obligation to the Provider;

(c) was known by or in the possession of the Recipient or its Representatives, as established by documentary evidence, prior to being disclosed by or on behalf of the Provider pursuant to this Agreement;

(d) was or is independently developed by the Recipient, as established by documentary evidence, without reference to or use of, in whole or in part, any of the Provider's Confidential Information; or

(e) was or is learned or established entirely from public sources, as established by documentary evidence, without reference to or use of, in whole or in part, any of the Provider's Confidential Information.

PROVIDED, however, that under no circumstance shall Critical Infrastructure Confidential Information ever be deemed to be excluded from being considered or deemed Confidential Information.

The parties acknowledge and understand that the confidentiality obligations of this Agreement apply only to the Confidential Information shared in connection with the Project. The parties may share other information with each other under other agreements, provisions or understandings which are not related to the Project. Such information sharing shall be subject to the provisions of the agreements and confidentiality provisions associated thereto and this Agreement shall not be construed to infringe upon or apply to such agreements or provisions.

4. Non-Disclosure of Confidential Information

Unless otherwise agreed to in writing by the Provider, the Recipient agrees as follows:

(a) except as required by law, not to disclose or reveal any Confidential Information to any person or entity other than its Representatives who are actively and directly participating in or advising on the evaluation, consummation, approval, development, investment, financing, construction or operation of the Project, and where the Companies are the Recipient, Companies' operation as an electric utility (the "Acceptable Purposes"), or those Representatives who otherwise need to know the Confidential Information for such Acceptable Purposes.

(b) not to use Confidential Information for any purpose other than in connection with the Acceptable Purposes.

(c) except as required by law, not to disclose to any person or entity (other than those of its Representatives who are actively and directly participating in the Acceptable Purposes or those Representatives who otherwise need to know such Confidential Information for such Acceptable Purposes) any information about the Project, or the terms or conditions or any other facts relating thereto, including, without limitation, the fact that discussions are taking place with respect thereto or the status thereof, or the fact that Critical Infrastructure Confidential Information has been made available to the Recipient or its Representatives.

(d) to use diligent efforts to safeguard and protect the confidentiality of the Confidential Information, including, at minimum, implementing the same commercial measures that the Recipient uses to protect its own confidential information. Before disclosing the Confidential Information to any Representative, the Recipient will inform such Representative of the confidential nature of such information, their duty to treat the Confidential Information in accordance with this Agreement and shall ensure that such Representative is legally bound by the terms and conditions of this Agreement or subject to confidentiality duties or obligations to the Recipient that are no less restrictive than the terms and conditions of this Agreement.

(e) Any provision herein to the contrary notwithstanding, the Companies and IPP may disclose Confidential Information to (i) the Commission's independent observer, provided that such disclosure is made pursuant to a non-disclosure agreement with the independent observer; and (ii) the Commission and/or the State of Hawaiʻi Division of Consumer Advocacy (including their respective staffs) provided that such disclosure is made under a protective order entered in the docket or proceeding with respect to which the disclosure will be made or any general protective order entered by the Commission. If IPP is a party or participant in the docket or proceeding under which disclosure of IPP's Confidential Information is being sought, IPP shall be solely responsible for providing the Justification associated with such Confidential Information.

5. Required Disclosure and Notice

If the parties or any of their Representatives become legally compelled (by deposition, interrogatory, request for documents, information request, subpoena, civil investigative demand, court order, or similar process) to disclose any of the Confidential Information (other than a situation covered by Section 4(e) above), the compelled party shall undertake reasonable efforts to provide the other party with notice within three (3) business days of such requirement or advice prior to disclosure so that the other party may (a) seek a protective order or other appropriate remedy, (b) consult with the other party with respect to the compelled party taking steps to resist or narrow the scope of such requirement or advice, and/or (c) waive compliance, in whole or in part, with the terms of this Agreement. If such protective order or other remedy is not obtained, or the other party waives compliance with the provisions hereof, the compelled party agrees to furnish only that portion of the Confidential Information which it is legally required to so furnish and, at the request of the other party, to use reasonable efforts to obtain assurance that confidential treatment will be accorded such Confidential Information, it being understood that such reasonable efforts shall be at the cost and expense of the party whose Confidential Information has been sought. In any event, neither the IPP nor any of its Representatives will oppose action by the Companies to obtain an appropriate protective order or other reliable assurance that confidential treatment will be accorded the Confidential Information.

6. Return or Destruction of Confidential Information

At any time during or after the term of this Agreement, at the Provider's written request, and in any event, upon the termination of the Agreement, the Recipient shall certify within ten (10) business days that it has destroyed all Confidential Information by using industry standard data elimination methods used to prevent unauthorized disclosure of information, and for Personally Identifiable Information, such methods shall be consistent with HRS Chapter 487-R; provided, however, that with respect to Confidential information in tangible form, the Recipient may return such Confidential Information to the Provider within ten (10) business days in lieu of destruction. The Recipient's sole obligation with respect to the disposition of any Notes shall be to redact or otherwise expunge all such Confidential Information from such Notes and certify to the Provider that it has so redacted or expunged the Confidential Information. Notwithstanding the foregoing, with respect to any Confidential Information stored in Recipient's disaster recovery backups or other electronic archives, Recipient is not required to destroy such Confidential Information if it would impose a material cost or burden; provided, however, such Confidential Information shall be destroyed when such archives are destroyed in accordance with Recipient's records retention policies.

7. Authority

Each party represents and warrants that it has full power and authority to enter into and perform this Agreement, and the person signing this Agreement on behalf of each has been properly authorized and empowered to enter into this Agreement, understands it and agrees to be bound by it.

8. No Representations or Warranties

Neither the Provider nor any of its Representatives make any express or implied representation or warranty as to the accuracy or completeness of any Confidential Information disclosed to the Recipient hereunder, and the Recipient agrees that it is not entitled to rely on the accuracy or completeness of any Confidential Information. Neither the Provider nor any of its Representatives shall be liable to the Recipient or any of its Representatives relating to or arising from the use of any Confidential Information or for any errors therein or omissions therefrom. Notwithstanding the foregoing, the Recipient shall be entitled to rely solely on such representations and warranties regarding Confidential Information as may be made to it in any final agreement relating to the Project, subject to the terms and conditions of such agreement.

9. No Other Obligations

Neither this Agreement nor the disclosure of the Confidential Information shall result in any obligation on the part of either party to enter into any further agreement with the other with respect to the subject matter hereof or otherwise, to purchase any products or services from the other, or to require either party to disclose any further information to the other. Nothing in this Agreement shall be deemed to constitute either party hereto as partner, agent or representative of the other party or to create any fiduciary relationship between the parties. Either party may offer products or services which are competitive with products or services now offered or which may be offered by the other. Subject to the express terms and conditions of this Agreement, neither this Agreement nor discussions and/or communications between the parties will impair the right of either party to develop, make, use, procure, and/or market any products or services, alone or with others, now or in the future, including those which may be competitive with those offered by the other. Whether or not the Project is consummated, neither party shall issue a press release or release any information to the general public concerning such transaction or the absence thereof without the express prior written consent of the other, and the parties agree that neither party will use the other's name whether by including reference to the other in any press release, list of customers advertising that its services are used by Companies or otherwise, without written authorization by the respective party's authorized representative.

10. Property Rights in Confidential Information

All Confidential Information shall remain the sole and exclusive property of the Provider and nothing in this Agreement, or any course of conduct between the parties shall be deemed to grant to the Recipient any license or rights in or to the Confidential Information of the Provider, or any part thereof. Unless otherwise expressly agreed in a separate license agreement, the disclosure of Confidential Information to the Recipient will not be deemed to constitute a grant, by implication or otherwise, of a right or license to the Confidential Information or to any patents or patent applications of the Provider.

11. Publicly Traded Company

The IPP acknowledges that the Companies' holding company is a publicly traded company, and that Confidential Information of the Companies may constitute material, non-public information with respect to the Companies. The IPP understands, and will advise its Representatives to whom Confidential Information of the Companies is disclosed, of the restrictions imposed by the United States securities laws on (a) the purchase or sale of securities by any person in possession of material, non-public information with respect to such securities, and (b) the communication of material, non-public information with respect to securities to a person who may purchase or sell such securities in reliance upon such information.

12. Remedies

(a) Each party acknowledges and agrees that any breach or threatened breach of this Agreement may give rise to an irreparable injury to the Provider or its Representatives, for which compensation in damages is likely to be an inadequate remedy. Accordingly, in the event of any breach or threatened breach of this Agreement by the Recipient or its Representatives, the Provider shall be entitled to seek equitable relief, including in the form of injunctions and orders for specific performance, in addition to all other remedies available at law or in equity.

(b) In the event that the Recipient learns of dissemination, disclosure, or use of the Confidential Information which is not permitted by this Agreement, the Recipient shall notify the Provider immediately in writing and shall use reasonable efforts to assist the Provider in minimizing damages from such disclosure. Such remedy shall be in addition to and not in lieu of any other rights or remedies available to the Provider at law or in equity.

(c) Recipient shall indemnify, defend and hold harmless Provider and Provider's officers, directors and employees (and each of their heirs, successors and assigns) (the "Indemnified Parties") from and against all losses, damages, claims and actions, including, without limitation, reasonable attorneys' fees and costs, and all expenses incidental to such losses, damages, claims or actions ("Losses"), based upon or arising out of, or to the extent caused or contributed to by the breach of Recipient's confidentiality obligations with respect to Critical

Infrastructure Confidential Information or Personally Identifiable Information; such rights to indemnification shall apply regardless of whether any act, omission, misconduct, negligence or default on the part of the Indemnified Parties contributed to the Losses, unless such act, omission, misconduct, negligence or default by an Indemnified Party was the sole or primary cause of the Losses.

13. Cumulative Remedies

No rights or remedy herein conferred upon or reserved to either party hereunder is intended to be exclusive of any other right or remedy, and each and every right and remedy shall be cumulative and in addition to any other right or remedy under this Agreement**,** or under applicable law, whether now or hereafter existing.

14. Notice

(a) By delivering written notice, either party may notify the other that it no longer wishes to receive or provide Confidential Information. Any further information received or provided by the party who received such notice following receipt of such notice, shall not be subject to the protection of this Agreement.

(b) All notices, consents and waivers under this Agreement shall be in writing and will be deemed to have been duly given when (i) delivered by hand, (ii) sent by electronic mail ("E-mail") (provided receipt thereof is confirmed via E-mail or in writing by recipient), (iii) sent by certified mail, return receipt requested, or (iv) when received by the addressee, if sent by a nationally recognized overnight delivery service (receipt requested), in each case to the appropriate addresses and E-mail Addresses set forth below (or to such other addresses and E-mail addresses as a party may designate by notice to the other party):

(1) Companies:

By Mail:

Hawaiian Electric Company, Inc.
P.O. Box 2750
Honolulu, Hawaii 96840
Attn: Manager of Procurement, Renewable Acquisition Division

Delivered By Hand or Overnight Delivery:

Hawaiian Electric Company, Inc.
Ward Receiving
Mail Code AL12-IU
799 S. King Street
Honolulu, Hawaii 96813
Attn: Manager of Procurement, Renewable Acquisition Division

By E-mail:

Hawaiian Electric Company, Inc.
Attn: Manager of Procurement, Renewable Acquisition Division
Email: renewableacquisition@hawaiianelectric.com

With a copy to:

By Mail:

Hawaiian Electric Company, Inc.
Legal Department
P.O. Box 2750
Honolulu, Hawaii 96840

Delivered By Hand or Overnight Delivery:

Hawaiian Electric Company, Inc.
American Savings Bank Tower
1001 Bishop Street, Suite 1100
Honolulu, Hawaiʻi 96813
Attn: Legal Department

By E-mail:

Hawaiian Electric Company, Inc.
Legal Department
Email: legalnotices@hawaiianelectric.com

(2) IPP

By Mail:

[INSERT ADDRESS/CONTACT]

Delivered By Hand or Overnight Delivery:

[INSERT ADDRESS/CONTACT]

By E-mail:

[INSERT ADDRESS/CONTACT]

With a copy to:

By Mail:

[INSERT ADDRESS/CONTACT]

Delivered By Hand or Overnight Delivery:

[INSERT ADDRESS/CONTACT]

By E-mail:

[INSERT ADDRESS/CONTACT]

15. No Waiver

Except as otherwise provided in this Agreement, no delay or forbearance of a party in the exercise of any remedy or right will constitute a waiver thereof, and the exercise or partial exercise of a remedy or right shall not preclude further exercise of the same or any other remedy or right.

16. Governing Law

This Agreement is made under, governed by, construed and enforced in accordance with, the laws of the State of Hawaiʻi. Any action brought with respect to the matters contained in this Agreement shall be brought in the federal or state courts located in the State of Hawaiʻi. Each party agrees and irrevocably consents to the exercise of personal jurisdiction over each of the parties by such courts and waives any right to plead, claim or allege that the State of Hawaiʻi is an inconvenient forum or improper venue.

17. Attorneys' Fees and Costs

If there is a dispute between the parties and either party institutes a lawsuit, arbitration, mediation or other proceeding to enforce, declare, or interpret the terms of this Agreement, then the prevailing party in such proceeding shall be awarded its reasonable attorneys' fees and costs.

18. Assignment Prohibited

This Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors, legal representatives, and permitted assigns. Neither party shall have the right to assign any of its rights, duties or obligations under this Agreement, by operation of law or otherwise, without the prior written consent of the other party. Any purported assignment in violation of this section shall be null and void.

19. No Third Party Beneficiaries

Nothing expressed or referred to in this Agreement will be construed to give any person or entity other than the parties any legal or equitable right, remedy, or claim under or with respect to this Agreement or any provision of this Agreement. This Agreement and all of its provisions and conditions are for the sole and exclusive benefit of the parties and their successors and permitted assigns.

20. Entire Agreement

This Agreement constitutes the entire agreement between the parties relating to the subject matter hereof, superseding all prior and contemporaneous agreements, understandings or undertakings, oral or written with respect to the subject matter. Any amendment or modification of this Agreement or any part hereof shall not be valid unless in writing and signed by the Parties. Any waiver hereunder shall not be valid unless in writing and signed via by the party against whom waiver is asserted.

21. Term and Survival

This Agreement shall remain in full force and effect for a period of five (5) years from the Effective Date. All confidentiality obligations of this Agreement with respect to Confidential Information provided to Recipient during the term of this Agreement shall survive following expiration or termination of this Agreement until such Confidential Information is returned to Provider or destroyed in accordance with Section 6 hereinabove.

22. Severability

If any term or provision of this Agreement, or the application thereof to any person, entity or circumstances is to any extent invalid or unenforceable, the remainder of this Agreement, or the application of such term or provision to persons, entities or circumstances other than those as to which it is invalid or unenforceable, shall not be affected thereby, and each term and provision of this Agreement shall be valid and enforceable to the fullest extent permitted by law, and the parties will take all commercially reasonable steps, including modification of the Agreement, to preserve the economic "benefit of the bargain" to both parties notwithstanding any such aforesaid invalidity or unenforceability.

23. Negotiated Terms

The parties agree that the terms and conditions of this Agreement are the result of negotiations between the parties and that this Agreement shall not be construed in favor of or against any party by reason of the extent to which any party or its professional advisors participated in the preparation of this Agreement.

24. Counterparts and Electronic Signatures

This Agreement may be executed in counterparts, each of which shall be deemed an original, and all of which shall together constitute one and the same instrument binding all parties notwithstanding that all of the parties are not signatories to the same counterparts. For all purposes, duplicate unexecuted and unacknowledged pages of the counterparts may be discarded and the remaining pages assembled as one document. The parties agree that this Agreement and any subsequent writings, including amendments, may be executed and delivered by exchange of executed copies via E-mail or other acceptable electronic means, and in electronic formats such as Adobe PDF or other formats mutually agreeable the parties which preserve the final terms of this Agreement or such writing. A party's signature transmitted by E-mail or other acceptable electronic means shall be considered an "original" signature which is binding and effective for all purposes of this Agreement.

[Signature Page Follows]

IN WITNESS WHEREOF, each party has caused this Agreement to be executed on its behalf by a duly authorized representative, all as of the Effective Date.

HAWAIIAN ELECTRIC COMPANY, INC.

By: ___________________________________
Print Name: ___________________________
Its: ___________________________________

"Company"

[Insert Name of IPP]

____

By: ___________________________________
Print Name: ___________________________
Its: ___________________________________

"IPP"

CONFIDENTIALITY, WAIVER, AND HOLD HARMLESS AGREEMENT
(Hawaiian Electric Stage 3 Oahu Documents)

1. This Confidentiality, Waiver, and Hold Harmless Agreement (the "Agreement"), effective upon execution, is executed by **[insert Developer]** ("Recipient"), in consideration of **HAWAIIAN ELECTRIC COMPANY, INC.** ("Hawaiian Electric") providing engineering standards, drawings and/or specifications for equipment owned or to be owned by Hawaiian Electric, in hard copy and/or electronic format (collectively the "Information"), as further identified in Section 7 below, at the request and for the convenience of and use by or on behalf of Recipient for its subject project described as follows: **[insert project]**.

2. The Information was prepared for the benefit of Hawaiian Electric only. The Information is being shared with Recipient solely for convenience and is provided "AS-IS", "WHERE IS" and "WITH ALL FAULTS". Hawaiian Electric GIVES NO REPRESENTATION EXPRESS OR IMPLIED INCLUDING ANY IMPLIED WARRANTIES OF QUALITY, MERCHANTABILITY, FITNESS FOR A PARTICULAR PURPOSE OR OTHERWISE REGARDING THE INFORMATION. Recipient understands, acknowledges and agrees that any reliance upon and use or reuse of such Information for any purpose is at Recipient's sole risk and without liability or legal exposure to Hawaiian Electric and is subject to Recipient's independent professional judgment and experience. Recipient is responsible for performing its own due diligence and making final decisions in all matters relevant to its project. Recipient further acknowledges and agrees that the Information may be updated or revised by Hawaiian Electric at any time or from time to time without further notice or obligation from Hawaiian Electric to Recipient regarding any such update or revision.

3. Recipient agrees to keep the Information confidential. If the Recipient becomes legally compelled (by deposition, interrogatory, request for documents, subpoena, civil investigative demand or similar process) or shall be advised by counsel to disclose any of the Information, Recipient shall undertake reasonable efforts to provide Hawaiian Electric with prompt notice of such requirement or advice prior to disclosure so that Hawaiian Electric may seek a protective order or other appropriate remedy or waive compliance with the terms of this Agreement. If such protective order or other remedy is not obtained, or Hawaiian Electric waives compliance with the provisions hereof, Recipient agrees to furnish only that portion of the Information which it is legally required to so furnish and, at the request of Hawaiian Electric, to use reasonable efforts to obtain assurance that confidential treatment will be accorded such Information, it being understood that such reasonable efforts shall be at the cost and expense of Recipient. Recipient shall not make copies, share or distribute the Information to any other person or entity without first receiving the prior express written consent of Hawaiian Electric, which consent may be granted or withheld in Hawaiian Electric's sole discretion; provided that, should Recipient receive Hawaiian Electric's consent, Recipient shall not make copies, share or distribute the Information without having first obtained from the intended recipient of the Information a duly signed Waiver and Hold Harmless Agreement of the form herein, and having delivered same to Hawaiian Electric.

4. Recipient, through its authorized undersigned representative, acknowledges receipt of such Information and hereby waives any and all rights that it might now or in the future have to claim or bring an action against Hawaiian Electric, its officers, directors, employees, agents and successors, on account of personal injury or death, or damage to or loss of property, arising out of, incident to, or resulting directly or indirectly from such use of Information, whether such injury, death, damage or loss is contributed to by the negligence of Hawaiian Electric, its officers, directors, employees, agents or servants, and whether due to any imperfections, errors, or omissions in such Information provided to Recipient.

5. Furthermore, Recipient does hereby agree to defend, indemnify, and hold harmless Hawaiian Electric, its officers, directors, employees, agents and successors against any and all actions, causes of action, suits, liabilities, claims, demands, damages, losses, costs or expenses, including but not limited to reasonable attorneys' fees and costs, arising out of, incident to, or resulting directly or indirectly from breach of this Agreement and/or the use of Information by or on behalf of Recipient. It is intended that the obligations agreed to herein shall be binding on the successors and assigns of Recipient.

6. This Agreement is made under and shall be governed by and construed in accordance with the laws of the State of Hawaii. Recipient agrees and consents that any dispute arising out of this Agreement, however defined, shall be brought in the State of Hawaii in a court of competent jurisdiction.

7. IDENTIFIED INFORMATION: **Copy of the HAWAIIAN ELECTRIC Document.**

Engineer, Procure, Construct Specifications for Hawaiian Electric Substations and Power Lines
Revision: August 2020

ACKNOWLEDGED, AGREED AND ACCEPTED BY:

[Insert Developer]

By_________________________________
Name:
Its:
Date: _________________________

By_________________________________
Name:
Its:
Date: _________________________

DRAFT

REQUEST FOR PROPOSALS

FOR

RENEWABLE DISPATCHABLE GENERATION

AND

ENERGY STORAGE

ISLAND OF O‘AHU

DECEMBER 22, 2022

Docket No. 2017-0352

Appendix F – [Reserved]

DRAFT

REQUEST FOR PROPOSALS

FOR

RENEWABLE DISPATCHABLE GENERATION

AND

ENERGY STORAGE

O‘AHU

DECEMBER 22, 2022

Docket No. 2017-0352

Appendix G – Hawaiian Electric Development Team Certification Form

Hawaiian Electric

Appendix G – Hawaiian Electric Proposal

Overview

To the extent that there are Hawaiian Electric Proposals to the RFP, the Company will endeavor to evaluate these Hawaiian Electric Proposals on a fair basis compared to third party Proposals. As described in Section 1.9.1 of the RFP, "[t]he Competitive Bidding Framework allows the Company the option to offer a Self-Build Proposal in response to this RFP ("Hawaiian Electric Proposal"). Accordingly, the Company must follow certain requirements and procedures designed to safeguard against and address concerns associated with: (1) preferential treatment of the Hawaiian Electric Proposal or members, agents or consultants of the Company formulating the Hawaiian Electric Development Team; and (2) preferential access to proprietary information to the Hawaiian Electric Development Team." A Hawaiian Electric Proposal will be required to comply with the provisions in the Framework for Competitive Bidding ("Framework") as well as this RFP.

In addition to its Proposal, the Hawaiian Electric Development Team will be required to submit Attachment 1 to this Appendix G, Hawaiian Electric Development Team Certification Form, acknowledging it has followed the rules and requirements of the RFP to the best of its ability and has not engaged in any collusive actions or received any preferential treatment or information providing an impermissible competitive advantage to the Hawaiian Electric Development Team over other proposers responding to this RFP, as well as adherence to PPA terms and milestones required of all proposers and the Hawaiian Electric Proposal's proposed cost protection measures.

Pursuant to the Framework and as set forth in the RFP Schedule, the Company will require that the Hawaiian Electric Proposal be submitted electronically through the Electronic Procurement Platform a minimum of one (1) day before other Proposals are due.

Except where specifically noted, a Hawaiian Electric Proposal must adhere to the same price and non-price Proposal requirements as required of all Proposers.

As described in Section 3.8.4 of the RFP, if selected, a Hawaiian Electric Proposer will not be required to enter into a Stage 3 Contract with the Company. However, the Hawaiian Electric Proposer will be held to the proposed modifications to the Stage 3 Contract, if any, it submits as part of the Hawaiian Electric Proposal in accordance with Section 3.8.7 of the RFP. Moreover, the Hawaiian Electric Proposal will be held to the same performance metrics and milestones set forth in the Stage 3 Contract to the same extent as all Proposers, as attested to in the Hawaiian Electric Development Team Certification submittal. If liquidated damages are assessed, they will be paid from shareholder funds and returned to customers through the Purchased Power Adjustment Clause or other appropriate rate adjustment mechanisms.

In lieu of price components, the Hawaiian Electric Proposal will need to provide their total project capital costs, any associated annual O&M costs, as well as annual revenue requirements by year (see Appendix B, Section 2.0). The Hawaiian Electric Proposal shall submit revenue requirement worksheets with their Proposal that support their annual revenue requirements estimates. (See Appendix B, Section 2.1.) A starter revenue requirements template example can be requested by the Hawaiian Electric Development Team via email to the RFP Email Address once the RFP event opens. The revenue requirements worksheets submitted will be customized by the Hawaiian Electric Development Team to reflect the details of the Project's Proposal. All assumptions used will be reflected in an assumptions input tab.

Hawaiian Electric Proposal Total Project Capital Cost

The following is a high-level breakdown followed by a narrative explanation of the total capital cost estimate for a potential Hawaiian Electric Proposal. The total project capital cost (and annual O&M costs) will be used to calculate the Revenue Requirement, which will then be used to calculate a for Proposal comparison purposes. The categories of costs include:

- Facility
    - EPC Contract
    - Allowance for Change Orders
    - Equipment
    - Owner's Cost
- Outside Services
- Interconnection
- Overheads
- AFUDC

These costs will be identified in Section 2.3.2.2 of the Hawaiian Electric Proposal(s). (See Appendix B, Section 2.3.2.2.)

- Facility (including any generation and storage components) **-** This line item, to the extent applicable, should include costs such as:

    Engineering, Procurement, and Construction ("EPC") Contract
    The total cost estimate of the facility is the projected EPC contract cost including the design of the facility up to the high-voltage terminals of the step-up transformers, procurement of all the equipment, and services necessary to build the facility and construction and commissioning of the facility.

    Allowance for Change Orders
    This allocation accounts for items such as additional requirements resulting from unforeseen conditions, unexpected permitting requirements, force majeure events, unanticipated interferences, different interpretations of design requirements, material unavailability, and longer than normal delivery times.

    Equipment
    This cost includes the generator and the facility equipment that support the operation of the generator and the distribution of electrical power around the station, as applicable. Engineering and testing services required to ensure that the equipment is properly functioning at the site, training and documentation necessary

to operate and maintain the equipment, and performance guarantees may also be included here.

Owner’s Cost
Owner’s costs for the facility are all the costs necessary for the design, permitting, procurement, construction, and commissioning of the facility and for the preparation of the Proposal that are not included in the major contracts (i.e. EPC). The Companies’ Labor includes Project Management, Station Operator training and commissioning, Environmental, Safety, Legal, Corporate Communications, Community and Government Relations, Engineering, and Regulatory Affairs. Company Labor for the preparation of the Proposal is also included here. For purposes of recovery, only the incremental costs of Labor will be subject to separate recovery.

- Outside Services **-** This line item, to the extent applicable, should include costs such as:
    - Construction Management to oversee the EPC contractor
    - Legal for the preparation of the Environmental Impact Statement and PUC process
    - Engineering for development and evaluation of the project technical specifications, Interconnection Requirements Study (IRS) and emissions testing
    - Environmental to conduct the Environmental Impact Statement (EIS) and Air Permit consulting
    - General Services such as surveys, land appraisals, Environmental Condition Reports, public relations, office trailer rental, archeological services, landscaping, miscellaneous permits, builder’s risk insurance, switchgear testing, hazard analysis, painting, monitoring services, and moving costs.
    - Material costs including spare parts, furnishings, IT equipment, appliances, generator system initial fills (fuels, oils, water), and telecommunications equipment for the station.
    - Travel costs required to inspect other similar facilities, observe final acceptance testing of critical equipment, and station operators’ factory training

- Interconnection – This line item covers all interconnection costs that a similarly situated IPP would be responsible for as described in RFP Section 2.3.5, and to the extent applicable, should include costs such as:

    Transmission Line
    The cost estimate includes the design, procurement, and construction of any new transmission infrastructure needed to interconnect with the designated substation.

Switchyard
Work at the switchyard will include design, procurement, and construction of the switchyard and the interfaces between the high voltage terminals of the generator step-up transformers and the transmission line to which it will be connected. Site preparation of the switchyard and the design, procurement, and installation of the step-up transformers located in the switchyard, are typically included in the EPC contract.

Substation
Work at the designated substation that will include the design, procurement, and construction of the interfaces between the new transmission line and the substation buswork to which it will be connected.

Telecom
Accounts for direct labor, materials, and outside services to install telecommunication requirements for the project.

Project Management
Cost estimate of the project management design, procurement, contracting, and scheduling efforts for the interconnection only. Project management costs for the facility are included in the Owner's Cost estimate above.

- Overhead Costs

Overhead costs for the proposed facility will be estimated by the Company's budgeting software (UI Planner) and represent an allocation for those Company costs that are not attributable to any particular project or operation, but are essential nonetheless. Overheads are comprised of non-productive wages (such as holiday, sick, and vacation pay), employee benefits, payroll taxes, corporate administrative costs, and clearing costs.

- Allowance for Funds Used During Construction ("AFUDC")

The AFUDC will be calculated using the Company's budgeting software (UI Planner) and represents the cost of capital funding for the Project. The Company strives to minimize the cost of the AFUDC by ensuring that Project elements that are used or useful are placed in service as soon as possible, as well as minimizing the amount of time that AFUDC can accumulate, by minimizing the amount of time between expenditures on Project elements and their placement in service.

The Hawaiian Electric Proposal will include a Revenue Requirement for each year, which is calculated from the total project capital cost to determine the revenues needed to recover the cost of the project. The value of the Revenue Requirement Calculation for the Total Hawaiian Electric Proposal Project Capital Cost will be included in the Levelized Price calculation described below.

Annual O&M

The cost for ongoing O&M (fixed and variable) will be a component of the Revenue Requirement. All O&M should be included in this category, unless captured elsewhere in the Revenue Requirement Calculation, including but not limited to annual O&M expense to maintain facility; property taxes (if applicable), and insurance. As described in RFP Appendix G, a Hawaiian Electric Proposal will be required to cap its O&M costs at the amount included in the Proposal. Only actual costs will be recovered if such actual costs are lower than the maximum amounts in the Proposal.

Annual Revenue Requirement

The Hawaiian Electric Proposal will include a Revenue Requirement for each year, which is calculated from the total project capital cost to determine the revenues needed to recover the cost of the project. The value of the Revenue Requirement Calculation for the Total Hawaiian Electric Project Capital Cost will be included in the Levelized Price calculation.

The following is a narrative description of the proposed revenue requirement calculation and significant assumptions that the Hawaiian Electric Proposal should account for. The objective of a revenue requirement analysis is to illustrate the annual revenue requirements (ARR) for a utility Hawaiian Electric Proposal.

Revenue Requirement is defined as a calculated value which represents the estimated revenues needed from ratepayers which would allow the Company to recover its capital investment and expenses, honor its debt obligations, pay its revenue and income tax liabilities and pay its preferred shareholders while providing a fair return to its common shareholders for their investment. Specific factors or assumptions related to that particular project will be included in the analysis.

The purpose of a revenue requirement calculation is to determine the annual and total revenue requirements of a capital investment and annual O&M expense needed from customers. The ratemaking formula for revenue requirements is shown below.

$$RR = O + T + D + r(RB)$$

Where:
RR = Revenue Requirements
O = Operating and Maintenance Expense
T = Tax Expense (Income and Revenue)
D = Depreciation Expense
r = Rate of Return on Rate Base
RB = Rate Base

The Company, in conjunction with the Independent Observer, may also conduct a risk assessment of the Hawaiian Electric Proposal to ensure an appropriate level of customer cost protection measures are included in such proposal.

APPENDIX G ATTACHMENT 1 – HAWAIIAN ELECTRIC PROPOSAL TEAM CERTIFICATION

Name of Hawaiian Electric Development Team Contact: ______________________________

Unique Name of Facility: ______________________________

This Hawaiian Electric Development Team Certification for Hawaiian Electric Company, Inc.s, ("Company") Proposal in response to the Company's Request for Proposals for Renewable Dispatchable Generation and Energy Storage ("RFP") is made as of the date stated below.

A. COMPLIANCE WITH THE RFP AND CODE OF CONDUCT

The Hawaiian Electric Development Team certifies and acknowledges that it will/has:

1. Adhered to the terms of the RFP applicable to the Hawaiian Electric Development Team, including but not limited to: Section 1.7 (proposal submittal requirements), Section 1.7.4 (certification of non-collusion), Section 1.9 (Procedures for any Hawaiian Electric Proposal or Affiliate Proposals), and Section 3.4.4 (authorized signatory);

2. Adhered to the technical requirements of the RFP, excluding however those requirements inapplicable to the Hawaiian Electric Development Team such as execution of the Stage 3 Contract, pricing formula requirements for independent power producer proposals, submission of a Proposal Fee, dispute resolution, credit requirements, selection of a priority list, and submission of a best and final offer;

3. Complied with the Company's Code of Conduct Procedures Manual, attached as Appendix C to this RFP, with particular attention to the Communications Protocols described in Section C therein with respect to communication with the Company RFP Team.

B. INDEPENDENT INVESTIGATION

The Hawaiian Electric Development Team further certifies and acknowledges that it will/has:

1. Submitted the Hawaiian Electric Proposal based on its own investigations, examinations and determinations, including assessments of any risks that could have an effect on its obligations under the Hawaiian Electric Proposal.

2. Carefully examined the RFP documents and its appendices and has a clear and comprehensive knowledge of what is required of a Proposer under the RFP, and correspondingly, what is required of the Hawaiian Electric Development Team.

3. Examined and understands the technical requirements, schedule and evaluation process as it is laid out in the RFP.

C. COST PROPOSAL ACKNOWLEDGEMENTS

The Hawaiian Electric Development Team acknowledges and agrees that:

1. Recovery for Project capital costs and O&M costs will be capped at the amount included in the Hawaiian Electric Development Team's Proposal.

2. Only actual capital costs and O&M costs will be recovered even if such actual costs are lower than the Hawaiian Electric Development Team's proposed maximum amounts.

3. Costs of developing the proposal must be included in the Hawaiian Electric Proposal for evaluation purposes only. Only the incremental costs of developing the Hawaiian Electric Development Team's proposal will be charged to the project and passed through to customers. Incremental costs for Hawaiian Electric Proposals not serving as the Parallel Plan and which are not selected to the Final Award Group will not be recoverable from the Companies' customers.

D. ADHERENCE TO PPA REQUIREMENTS AND MILESTONES

The Hawaiian Electric Development Team acknowledges and agrees that:

1. The Hawaiian Electric Proposal will be consistent with the scope of work and responsibilities of the "Seller" under the terms of the applicable model Stage 3 Contract excluding inapplicable terms related to commercial and legal interactions between the Seller and the Company.

2. The Hawaiian Electric Proposal Facility will be designed and constructed to:

    a. Achieve the Performance Standards identified in Attachment B, Section 3 of the applicable model Stage 3 Contract, as modified by the IRS (subject to reasonable adjustment agreeable to the Company consistent with the Company's negotiation of such performance standards that would be completed with an independent power producer under similar circumstances);

    b. Meet the performance metrics as specified in the applicable model Stage 3 Contract.

        b.1. For facilities with a photovoltaic generation component, (i) PV System Equivalent Availability Factor, and (ii) Measured Performance Ratio;
        b.2. For facilities with a wind generation component, (i) Modified Pooled OMC Equipment Availability Factor, (ii) Performance Index, and (iii) Balance of Plant Efficiency Ratio;
        b.3. For Storage facilities (paired storage or standalone storage), (i) Storage Annual Equipment Availability Factor, (ii) Storage Annual Equivalent Forced Outage Factor, and (iii) Storage Capacity Ratio;

    c. Pass the Acceptance Test specified in the applicable Acceptance Test General Criteria section of the applicable model Stage 3 Contract;

d. Pass the Control System Performance Test specified in the applicable Control System Acceptance Test Criteria section of the applicable model Stage 3 Contract;

e. If applicable, pass the On-line Performance Test specified in the applicable BESS Capacity Test section of the applicable model Stage 3 Contract;

f. If applicable, achieve a Demonstrated Capacity equal to or greater than that indicated in the Hawaiian Electric Proposal as measured pursuant to the applicable BESS Capacity Test section of the applicable model Stage 3 Contract;

g. Meet the project milestones identified in the Hawaiian Electric Proposal no later than the dates specified therein, which shall be consistent with the guaranteed project milestones required in the Guaranteed Project Milestones section of the applicable model Stage 3 Contract (subject to reasonable adjustment agreeable to the Company consistent with the Company's negotiation of such milestones that would be completed with an independent power producer under similar circumstances). Notice of completion of milestones and any delay will be provided to PUC and Consumer Advocate.

h. Achieve the reporting milestones identified in the Hawaiian Electric Proposal no later than the dates specified therein, which shall be consistent with the reporting milestones required in the Reporting Milestones of the applicable model Stage 3 Contract (subject to reasonable adjustment agreeable to the Company consistent with the Company's negotiation of such milestones that would be completed with an independent power producer under similar circumstances). Notice of completion of milestones and any delay will be provided to PUC and Consumer Advocate.

i. Will be subject to the applicable liquidated damages for the Stage 3 Contract provisions above. These liquidated damages would be paid from shareholder funds and would be passed through to customers through the Companies' Power Purchase Adjustment Clause or other appropriate rate adjustment mechanisms. Notice of any liquidated damages assessed and amounts of such liquidated damages will be provided to PUC and Consumer Advocate.

j. Will reconfirm requirements in GO7 application and any resulting approval order for such application.

k. Will provide annual report to PUC and Consumer Advocate on performance metrics.

E. DECLARATION AND SIGNATURE

1. The individual(s) that has (have) signed this Hawaiian Electric Development Team Certification is (are) duly authorized by the Hawaiian Electric Development Team to execute such on behalf of the Hawaiian Electric Development Team; and

2. All statements, specifications, data, confirmations and other information set out in this Hawaiian Electric Development Team Certification are complete and accurate in all material respects.

IN WITNESS WHEREOF, the HAWAIIAN ELECTRIC DEVELOPMENT TEAM hereby makes the certifications, acknowledgements and agreements stated herein as of the date stated under the signature of its authorized representative:

Dated at __________________, _________ this _____________ day of ________________ 20________.

____
Signature of Hawaiian Electric Development Team Representative

____
Name of Hawaiian Electric Development Team Representative (please print)

____
Title of Hawaiian Electric Development Team Representative (please print)

DRAFT

REQUEST FOR PROPOSALS

FOR

RENEWABLE DISPATCHABLE GENERATION

AND ENERGY STORAGE

ISLAND OF O‘AHU

DECEMBER 22, 2022

Docket No. 2017-0352

Appendix H – Interconnection Facilities Cost and Schedule Information

Hawaiian Electric

TABLE OF CONTENTS

To assist Proposers in estimating costs of potential projects, the information provided in this document can be used to approximate the cost for Company-Owned Interconnection Facilities (COIF), including substation, telecommunications, security, transmission and distribution lines, and project management.

Tariff Rule No. 19, approved by the PUC, establishes provisions for Interconnection and Transmission Upgrades (https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/). The tariff provisions are intended to simplify the rules regarding who pays for, installs, owns, and operates interconnection facilities in the context of competitive bidding. Tariff Rule No. 19 and applicable RFP requirements will be utilized as the basis for addressing interconnection and transmission upgrades for any projects developed. Proposers will comply with the terms and conditions as specified therein.

SECTION 1 – COST RESPONSIBILITIES

The purpose of Section 1 is to clearly define the cost responsibilities of construction, replacements, and upgrades of Company-Owned Interconnection Facilities (COIF) and existing Company-owned facilities in compliance with Tariff Rule No. 19.

1.1 – DEFINITIONS

1. Betterment – Any upgrading to a facility made solely for the benefit of and at the election of the Company and is not required by applicable laws, codes, Company Standards, and the interconnection requirements in accordance with Tariff Rule No. 19.
2. Company – Hawaiian Electric, Maui Electric, or Hawaiʻi Electric Light.
3. Company-Owned Interconnection Facilities – The equipment and devices owned by Company that are required to permit a generating facility to operate in parallel with and deliver electric energy to Company's system and provide reliable and safe operation of, and power quality on, Company's system.
4. Grid Connection Point – The point that the new interconnection facilities associated with the Proposer's project interconnects to the Company's existing electrical grid.
5. Interconnection Agreement – The executed contract between the Company and Proposer (e.g., Power Purchase Agreement, Standard Interconnection Agreement, etc.).
6. Point of Interconnection – The point of delivery of energy supplied by Proposer to Company, where the Facility owned by the Proposer interconnects with the facilities owned or to be owned by the Company.
7. Proposer – The developer proposing a renewable project in response to a Company RFP.

1.2 – ABBREVIATIONS

1. ADSS – All Dielectric Self-Supporting
2. COIF – Company-Owned Interconnection Facilities
3. CT – Current Transformer
4. DFR – Digital Fault Recorder

5. DTT – Direct Transfer Trip
6. FS – Facility Study
7. GCP – Grid Connection Point
8. HVAC – Heating, Ventilation, and Air Conditioning
9. IRS – Interconnection Requirements Study (includes both SIS and FS)
10. NDA – Non-Disclosure Agreement
11. OPGW- Optical Ground Wire
12. POI – Point of Interconnection
13. PT – Potential Transformer
14. RTU – Remote Terminal Unit
15. SCADA – Supervisory Control and Data Acquisition
16. SIS – System Impact Study
17. UFLS – Under-Frequency Load Shed

1.3 – FACILITIES AT PROPOSER SITE

1. Proposer shall be responsible for all costs related to COIF at the Proposer site required by any relevant Rule or Tariff, Request for Proposal, and/or the IRS. This may include, but is not limited to:
   a. Project management, design, permitting/regulatory fees and approvals, land rights, installation labor, inspection, construction management, and testing
   b. Site work (grading, trenching, manholes/handholes, conduits, cable trench, concrete pads/foundations, fencing, roadways/driveways, ground grid, lighting, etc.)
   c. Substation structures, design, and configuration (i.e., breaker and a half, ring bus, etc.)
   d. Control equipment enclosure/cabinet
   e. Equipment (circuit breakers, transformers, relays, switches, arresters, batteries, HVAC, RTU, DFR, DTT, meters, PTs, CTs, etc.)
   f. Telecommunication equipment (See Telecommunication Facilities section below)
   g. Electrical work (bussing, wiring, lightning protection, fiber optic cable, etc.)
   h. Security systems/equipment
2. Company shall be responsible for Betterment costs.

1.4 – PROPOSER FACILITY SERVICE POWER AND COMPANY SWITCHING STATION POWER

1. For all distribution-level service power, Proposer shall submit an Electrical Service Request Form via www.hawaiianelectric.com. Please refer to the Large Customer New Service Request brochure for milestones and estimated timeline.
2. Proposer shall be responsible for all costs related to providing service power to the Proposer's facility. Facility service power is NOT a part of COIF, but Proposers should account for it in the total costs to build the project.
3. Station power is required if a new Company switching station or substation is built to allow the interconnection of the Proposer's project. If station power is required, the

Proposer shall be responsible for all costs related to the primary and backup station power sources. This may include, but is not limited to:

a. Project management, design, permitting/regulatory fees and approvals, land rights, installation labor, inspection, construction management, and testing
b. Overhead electrical facilities (poles, conductor, insulators, crossarms, guy wires, transformers, etc.)
c. Underground electrical facilities (cables, splices, termination, grounding, transformers, switchgears, etc.)
d. Step-down transformer
e. Civil/structural work (survey, grading, trenching, conduits, manholes/handholes, concrete pads, concrete pier foundations, pole hole excavation, etc.)
f. Vegetation trimming and traffic control

4. Options for primary station power sources for the Company's various switching station voltages are:
    a. Tap off the bus through a step-down transformer for 23kV through 69kV
    b. 12kV line extension and service transformer for 23kV through 138kV
    c. Gensets are not an allowable substitute for the above options
5. Proposer shall be responsible for obtaining all permitting and land rights.

1.5 – REMOTE SUBSTATION FACILITIES

1. Proposer shall be responsible for all costs for work at remote substations caused by the interconnection of Proposer's project. This may include, but is not limited to:
    a. Project management, design, permitting/regulatory fees and approvals, land rights, installation labor, inspection, construction management, and testing
    b. Site work (grading, trenching, manholes/handholes, conduits, cable trench, concrete pads/foundations, fencing, roadways/driveways, ground grid, lighting, etc.)
    c. Substation structures
    d. New control equipment cabinet or existing enclosure expansion
    e. Equipment (circuit breakers, transformers, relays, switches, arresters, batteries, HVAC, DFR, DTT, meters, PTs, CTs, etc.)
    f. Electrical work (bussing, wiring, lightning protection, fiber optic cable, etc.)
    g. Telecommunications equipment
    h. Company has completed a high-level analysis to determine anticipated remote substation requirements prior to the RFP. Proposer may ask Company for a list of those requirements based on Proposer's indicated interconnection point after Proposer has signed a Non-Disclosure Agreement (NDA). Such requirements will be confirmed in the Interconnection Requirements Study.
2. Company shall be responsible for the following costs:
    a. Betterment
    b. Changes to the Under-Frequency Load Shed (UFLS) scheme

1.6 – INTERCONNECTION TO SPECIFIC COMPANY SITES

1. Proposer shall be responsible for all costs related to COIF required at the Company's site by any relevant Rule or Tariff, Request for Proposal, and/or the IRS. This may include, but is not limited to:
    a. Project management, design, permitting/regulatory fees and approvals, land rights, installation labor, inspection, construction management, and testing
    b. Site work (grading, trenching, manholes/handholes, conduits, cable trench, concrete pads/foundations, fencing, roadways/driveways, ground grid, lighting, etc.)
    c. Substation structures, design, and configuration (i.e., breaker and a half, ring bus, etc.)
    d. Control equipment enclosure/cabinet
    e. Equipment (circuit breakers, transformers, relays, switches, arresters, batteries, HVAC, RTU, DFR, DTT, meters, PTs, CTs, etc.)
    f. Telecommunication equipment (See Telecommunication Facilities section below)
    g. Electrical work (bussing, wiring, lightning protection, fiber optic cable, etc.)
    h. Security systems/equipment
2. Company shall be responsible for Betterment costs.

1.7 – LINE EXTENSION FROM GRID CONNECTION POINT (GCP) TO PROPOSER SITE

1. Proposer shall be responsible for all costs related to the line extension between the GCP and the Proposer site. This may include, but is not limited to:
    a. Project management, design, permitting/regulatory fees and approvals, land rights, installation labor, inspection, construction management, and testing
    b. Overhead electrical facilities (poles, conductor, insulators, crossarms, guy wires, etc.)
    c. Underground electrical facilities (cables, splices, terminations, grounding, transformers, switchgears, etc.)
    d. Civil/structural work (survey, grading, trenching, conduits, manholes/handholes, concrete pads, concrete pier foundations, pole hole excavation, etc.)
    e. Company fiber (ADSS fiber, OPGW shieldwire, splice boxes, etc.)
    f. Vegetation trimming and traffic control
2. The Company shall be responsible for the following costs:
    a. Betterment

1.8 – T&D SYSTEM UPGRADES

1. Proposer shall be responsible for all costs related to system upgrades or changes required to accommodate the Proposer's project (e.g., reconductoring or recircuiting of existing lines that do not have the required ampacity, re-fusing or re-programming of protective devices upstream of the GCP, etc.).

1.9 – COMPANY-OWNED FIBER

1. If Company-owned fiber is used to satisfy the communications requirements in the IRS, then the Proposer shall be responsible for all costs related to routing the ADSS fiber or OPGW from the nearest existing splice point to the Proposer site. This may include, but is not limited to:
    a. Project management, design, permitting/regulatory fees and approvals, land rights, installation labor, inspection, construction management, and testing
    b. Company fiber-optic cable (ADSS fiber cable or OPGW shieldwire) and associated equipment/hardware (splice boxes, innerduct, vibration dampers, etc.)
    c. Splicing and Testing of fiber strands
    d. Pole replacements and additional equipment if needed for additional capacity
    e. Civil/structural work (survey, grading, trenching, conduits, manholes/handholes, concrete pads, concrete pier foundations, pole hole excavation, etc.)
    f. Vegetation trimming and traffic control
2. Company will provide the location(s) of the nearest fiber splice point(s) after the Proposer has signed a Non-Disclosure Agreement (NDA).
3. Company shall be responsible for Betterment costs.

1.10 – TELECOMMUNICATION FACILITIES

1. Telecommunication Cabinet
    a. If a control equipment enclosure will not be built, the Proposer shall be responsible for all costs related to installing a telecommunication cabinet required to accommodate the telecommunication equipment at the Proposer's facility. This may include, but is not limited to equipment racks and ancillary infrastructure, 48V DC Power System (includes 48V DC Charger w/ at least 12-hr battery backup), alarming, and air conditioning.
2. Telecommunication Power
    a. Proposer shall be responsible for all costs related to providing reliable 48V DC power to Company equipment at a new Company switching station or a Proposer-owned station. This may include, but is not limited to battery racks, banks, fuse panels, and associated power system equipment.
3. Fiber Termination Equipment
    a. If Company-owned fiber is used to satisfy the communication requirements in the IRS, then the Proposer shall be responsible for all costs related to terminating the ADSS fiber or OPGW at the new Company switching station and point of interconnection to Company's existing system. This may include, but is not limited to a fiber termination panel and associated equipment/hardware (fiber guide, splice trays, connectors, etc.).
4. Microwave Radio or Wireless Radio
    a. If Company-owned microwave radio (6GHz, 10/11 GHz, etc.) or Company-owned wireless radio (900MHz, 450MHz, etc.) is used to satisfy the communications requirements in the IRS, then the Proposer shall be

responsible for all costs related to installing the microwave or wireless radio/link at the new Company switching station and remote site(s). This may include, but is not limited to:

i. Pre-design requirements (path survey/engineering, FCC frequency coordination, licensing, filings, EME study if required, etc.)
ii. Project management, design, permitting, regulatory fees and approvals, land rights, labor, inspection, construction management, and testing
iii. Pole or tower facilities to support the microwave dish and its connection to the microwave equipment (waveguide, cables, conduit, etc.)
iv. Civil/structural work (survey, grading, trenching, conduits, manholes/handholes, concrete pads, concrete pier foundations, pole hole excavation, etc.)
v. Antenna system design and installation

5. Leased Service
   a. If 3rd party leased service will provide telecommunication connectivity to the new Company switching station, then the Proposer shall be responsible for all costs related to ordering and installing the leased service at the site. This may include, but not be limited to the initial cost to establish the leased line(s) required for the project, monthly recurring leased cost of the service(s), and on-going maintenance of the service(s).
6. Telecommunication Service Equipment
   a. Telecommunication equipment is required to provide circuits to support the various applications at the new Company switching station. The Proposer shall be responsible for all costs related to installing the telecommunication equipment. This may include, but is not limited to:
      i. Project management, design, installation, and testing
      ii. Telecommunication routers, multiplexors, and associated equipment/hardware

1.11 – CONTROL SYSTEM ACCEPTANCE TEST (CSAT)

1. Proposer shall be responsible for all costs related to the CSAT, including all Company costs in support of the Proposer's CSAT.

1.12 – PROPOSER PAYMENTS

1. The Company shall require upfront payment prior to the commencement of any phase of work based on an estimate of Company costs for that phase. A true-up at the end of the project shall be completed and a refund or bill shall be processed in accordance with the Interconnection Agreement when necessary.
2. Proposer is also responsible for payments to the Company related to service contracts for service power.

SECTION 2 – INTERCONNECTION REQUIREMENTS AND COSTS

The information in Section 2 is based on typical interconnections as shown in the Attachments referenced. Conceptual design is not intended to cover all interconnection requirements. Final interconnection design will be subject to the results of a technical review. The per-unit cost figures below should not be used to create a detailed project estimate. A detailed project estimate typically requires a certain level of engineering to assess project site conditions and to factor in other parameters specific to the project.

The Proposer should identify the components assumed for their project and the quantity assumed for each. Each table below provides notes on the assumptions for each of the unit cost estimates. If a Proposer's project requirements are different than what is assumed in the notes, the Proposer should identify each difference and provide an estimated additional cost or savings resulting from those differences. Please see Attachment 1 for examples of how to apply the per-unit costs provided. All costs provided are Company costs only and do not include costs related to Proposer responsibilities including, but not limited to, permitting, land rights, community outreach, biological and/or cultural (archeological) surveys. Proposers should do their own due diligence for these costs.

For the purposes of Section 2, voltages are classified as follows:

- Subtransmission – 46kV
- Transmission – 138kV

2.1 – SUBSTATION & METER BASELINE COSTS

A. Not Used

B. Typical Subtransmission Interconnection

The costs in Section 2.1B are reflective of typical standard interconnections to existing circuits at subtransmission voltages. Costs for interconnection to specific Company sites are shown in Section 2.2. Costs are for Proposer-Build projects.

Item	Description	Cost
15	Attachment 2 – 46kV Variable Project	$403,000
16	Attachment 3 – 46kV Firm Project	$1,041,000
Remote Sub Work		
21	For Radial Circuits – Components at Company's 46kV remote substation, including DTT and relaying requirements	$435,000 / site
22	For Paralleled Circuits – Components at Company's 46kV remote substation, including DTT and Relay Upgrades	$561,000 / site

Item	Description	Cost
Notes: a) Costs provided are in 2022 dollars. b) Includes Company costs for engineering, materials, construction, and testing for Company-responsible items (See Section 3) related to Substation & Meter components as shown in the referenced attachment. c) Does NOT include T&D, Project Management, Telecommunications, or Security costs. d) Civil infrastructure and space for COIF for Items 15 and 16 provided by Proposer. e) Substation relay protection requirements have not been identified so costs are based upon typical line protection relaying requirements. f) Does not include costs for permitting, land rights, or a Relay Coordination Study. g) For T&D costs (including service power costs) – See Section 2.3. h) For Project Management costs – See Section 2.4. i) For Telecommunications costs – See Section 2.5. j) For Security requirements – See Section 2.6.		

C. Typical Transmission Interconnection

The costs in Section 2.1C are reflective of typical standard interconnections to existing circuits at transmission voltages. Costs for interconnection to specific Company sites are shown in Section 2.2. Costs are for Proposer-Build projects.

Item	Description	Cost
At New 138kV Switching Station		
32	Attachment 4 – 138kV Interconnection to Two (2) Existing Circuits (4-Bay BAAH configuration)	$2,105,000
Remote Sub Work		
36a	138kV line relay upgrades	$452,000 each
36b	138kV circuit breaker replacement	$569,000 each
36c	DTT for anti-islanding	$108,000 each
Notes: a) Costs provided are in 2022 dollars. b) Includes Company costs for engineering, materials, construction, and testing for Company-responsible items (See Section 3) related to Substation & Meter components as shown in the referenced attachment. c) Item 32 is required for all interconnections to existing 138kV lines. Please contact Company for more information on if Items 36a-c are required for a proposed GCP. d) Does NOT include T&D, Project Management, Telecommunications, or Security costs. e) Civil infrastructure and space for COIF for Item 32 provided by Proposer. f) Substation relay protection requirements have not been identified so costs are based upon typical line protection relaying requirements. g) Does not include costs for permitting, land rights, or a Relay Coordination Study. h) For T&D costs (including service power costs) – See Section 2.3. i) For Project Management costs – See Section 2.4. j) For Telecommunications costs – See Section 2.5. k) For Security requirements – See Section 2.6.		

Item	Description	Cost

2.2 – INTERCONNECTION TO SPECIFIC COMPANY SITES

Section 2.2 includes baseline costs for interconnection at specific Company sites identified in the RFP. Attachments 5-12 of Appendix H will be provided to Prospective Proposers who request the information via the communication method identified in Section 1.6 of the RFP and upon execution of an NDA as specified in Section 3.12.1 of the RFP. If a site is not specifically identified in the RFP, please use the typical costs in the previous sections for the applicable voltage and project size. Costs are for Proposer-Build projects. See Section 3 for responsibilities.

A. Waiau 46kV GIS Substation

Please refer to Attachment 5 for a single line diagram depicting the required interconnection to the Company's system at the Waiau 46kV GIS Substation. There are two (2) terminations available for use with the planned retirement of Waiau 3 & 4. Proposers should assume the new GIS substation will be completed by mid-2025. Costs shown assume a Proposer-Build project.

Item	Description	Cost
At Proposer's Project Site		
40a	Company work for components at the Project Site on the Company side of the demarcation as shown in Attachment 5	$403,000
At Existing Waiau 46kV GIS Substation		
40b	1st Termination – Terminate into existing spare breaker position. Utilize existing spare GIS breaker, switches, PTs and CTs	$213,000
40c	2nd Termination – Add new GIS breaker and associated equipment into existing open bay position	$814,000

Item	Description	Cost
Notes: a) Costs provided are in 2022 dollars. b) Includes Company costs for engineering, materials, construction, and testing for Company-responsible items (See Section 3) related to Substation & Meter components as shown in the referenced attachment. c) Does NOT include T&D, Telecommunications, or Security costs. d) Civil infrastructure and space for COIF for Item 40a provided by Proposer. e) Substation relay protection requirements have not been identified so costs are based upon typical line protection relaying requirements. f) Does not include costs for permitting, land rights, or a Relay Coordination Study. g) For T&D costs (including service power costs) – See Section 2.3. Add Item 123 (1st and 2nd termination) for costs to riser into the substation. h) For Project Management costs – See Section 2.4. i) For Telecommunications costs – See Section 2.5. j) For Security requirements – See Section 2.6. k) For typical durations to support Proposer-Build facilities – See Section 4.2. l) For additional durations to interconnect at Waiau 46kV GIS Substation – See Section 4.4.		

B. Company-Identified 138kV Sites

The following table provides details about interconnecting to the available substations and how to apply the per unit costs to each site. Each termination is limited to the 142MW Single Point of Failure limit.

Existing 138kV Substations Available for Interconnection
AES Substation (Attachment 6) • Only available if replacing the existing IPP generation interconnected to this substation. • 1st Termination – Available after AES decommissioned. Add Item 45. • 2nd Termination – Space for additional BAAH bay with substation expansion. Add Items 42, 43, and 46.
Ewa Nui Substation (Attachment 7) • Space for two (2) terminations is available. Routing new 138kV lines into the substation may be difficult due to future planned buildout around the existing substation. One (1) new BAAH bay required for each termination. Add Item 43 for each termination.
Kahe Substation (Attachment 8) • Space for three (3) terminations is available. One (1) new BAAH bay required for each termination. Add Item 43 for each termination.
Hoohana Substation (Attachment 9) • Assumes substation is completed (scheduled for 2023) • Space for three (3) terminations is available. • 1st Termination – Terminate into open position. Add Item 44. • 2nd Termination – Expand substation perimeter for two (2) additional BAAH bays. Cut and terminate Kahe-Halawa 2 circuit into substation. Add one (1) full BAAH bay with two (2) terminations, one (1) BAAH bay with one (1) termination, and a new control house. Add Items 42 (x2), 43 (x2), 44, 46, and 47. • 3rd Termination – Terminate interconnecting line to last open position. Add Item 44.

Existing 138kV Substations Available for Interconnection
Waiau 138kV Substation (Attachment 10) • Four (4) terminations available (to replace existing Waiau 5 & 6 and/or Waiau 7 & 8 generation units). • Add item 45 for each.
CEIP Substation (Attachment 11) • One (1) termination is available. Routing new 138kV lines into the substation may be difficult due to future planned buildout around the existing substation. Add one (1) new BAAH bay with new termination. Add Item 43.
Koolau Substation (Attachment 12) • One (1) termination is available. Add two (2) new breakers to an existing BAAH bay. Add Item 44 (x2). • Routing lines to this site may be difficult due to permitting issues.

C. Costs for Interconnection to Company-Identified 138kV Sites

The following table provides the per unit costs of typical items required for interconnecting at the identified existing substations.

Item	Description	Cost
At Proposer's Project Site		
41	Company work for components at the Project Site on the Company side of the demarcation as shown in Attachments 6-12	$408,000
At Existing Company Substation		
42	Expansion of substation perimeter (per BAAH bay) • Includes grading, fencing, and ground grid	$500,000
43	Add BAAH bay with one (1) new termination • Includes 2 breakers, PTs, switches, structures, and relays • Assumes no control house expansion needed	$2,975,000
44	Add termination to an existing BAAH bay • Includes 1 breaker, PTs, and relays	$1,151,000
45	Replace existing termination for generation being retired • Assumes line relays need to be upgraded but high voltage equipment and structures do not need to be replaced	$452,000
46	New control house	$2,000,000
47	Cut and terminate Kahe-Halawa 2 circuit into Hoohana Substation • Includes 3 steel poles, 740 circuit feet of OH conductor, and undergrounding 270 feet of existing lines to accommodate OH termination	$3,557,000
Notes: a) Costs provided are in 2022 dollars. b) Includes Company costs for engineering, materials, construction, and testing for Company-responsible items (See Section 3) related to Substation & Meter components as shown in Attachments 6-12. c) Does NOT include Telecommunications or Security costs. d) Does NOT include T&D costs for the gen-tie line.		

Item	Description	Cost
	e) Civil infrastructure and space for COIF for Item 41 and 47 provided by Proposer. f) Substation relay protection requirements have not been identified so costs are based upon typical line protection relaying requirements. g) Does not include costs for permitting, land rights, or a Relay Coordination Study. h) For T&D costs (including service power costs) – See Section 2.3. i) For Project Management costs – See Section 2.4. j) For Telecommunications costs – See Section 2.5. k) For Security requirements – See Section 2.6. l) For typical durations to support Proposer-Build facilities – See Section 4.3. m) For additional durations to interconnect at an existing substation – See Section 4.4.	

2.3 – T&D BASELINE AND LINE EXTENSION COSTS

A. Not Used

B. Typical Subtransmission Interconnection Baseline

The costs in Section 2.3B are the baseline T&D costs for interconnections at subtransmission voltages. It includes an OH or UG line extension as specified in the Item description below. For any extensions greater than the specified length, please add costs per Section 2.3D. Costs are for Proposer-Build projects.

Item	Description	Cost
120	46kV OH to OH Final Tap by Company (Attachments 2 and 3) • Includes 1 wood pole, 1 span (100ft) OH line extension toward Proposer facility and assumes Proposer designs, procures, and installs the required gang-operated switch	\$86,000 (1st tap) \$51,000 (2nd tap)
121	46kV OH to UG Final Tap by Company (Attachments 2, 3, & 5) • Includes 1 wood pole, 1 gang-operated switch, 100ft UG line extension and splice in Proposer-installed manhole	\$241,000 (1st tap) \$188,000 (2nd tap)
122	46kV UG to UG Final Tap by Company (Attachments 2 and 3) • Includes cut and splicing in existing Company manhole, a 100ft UG line extension and terminations at a Proposer-installed riser pole for one set of cables, and 100ft UG line extension and splices in a Proposer-installed manhole	\$263,000 (1st tap) \$210,000 (2nd tap)
123	46kV Terminations to Existing Waiau 46kV GIS Substation • Includes terminations at Waiau GIS Substation, cable racking under the GIS platform, 190ft UG line extension and splices at a Proposer-installed manhole • Proposer is responsible for installing civil infrastructure connecting to the existing cable trench stubbed out 20ft from the south side of the GIS substation	\$290,000 (1st termination) \$236,000 (2nd termination)
Notes: a) Costs provided are in 2022 dollars.		

Item	Description	Cost
b) Includes Company costs for engineering, materials, construction, and testing of Company-responsible items. See Section 3 for Proposer-Build responsibilities. c) Interconnection for variable RDG will require a final tap to one circuit (1st tap only). d) Interconnection for firm RDG will require final taps to two circuits. Proposers should include a 1st and a 2nd tap cost as appropriate depending on the existing facilities in the area and/or the type of construction for any line extension. e) OH or UG line extensions greater than specified length in the Item description – Add applicable costs per Section 2.3D. f) OH/UG route and civil infrastructure drawings provided by Proposer. g) Civil infrastructure (pads, MH/HHs, conduits, etc.) is designed, procured, and installed by Proposer. h) Includes review of Proposer civil infrastructure designs and materials and inspection of Proposer civil infrastructure construction. i) Does not include vegetation clearing, grading, dewatering, permitting or land rights.		

C. Typical Transmission Interconnection Baseline

The costs in Section 2.3C are the baseline T&D costs for interconnections at transmission voltages. It includes 100ft of OH or UG line extension. For any extensions > 100ft, please add costs per Section 2.3D. Costs are for Proposer-Build projects.

Item	Description	Cost
133	138kV OH to OH Final Tap by Company (Attachment 4) • Includes 2 steel poles, 1 span (100ft) OH line extension from each new pole toward Proposer facility and the removal of existing conductors between the new poles	$962,000 per circuit
135	138kV OH Final Span for Termination to Existing Substation by Company (Attachments 6-12) • Includes 1 span (100ft) of 138kV conductors and 2 spans (100ft each) of shield wire from steel pole to substation termination structure	$100,000 each
136	138kV UG Termination to an Existing Substation by Proposer (Attachments 6-12) • Includes Company costs for Company-responsible items – See Section 3.	$34,000 each
Notes: a) Costs provided are in 2022 dollars. b) Includes Company costs for engineering, materials, construction, and testing of Company-responsible items. See Section 3 for Proposer-Build responsibilities. c) Interconnection will typically require one of these items depending on the existing facilities in the area and/or the type of construction for any line extension. d) OH or UG line extensions (if > 100ft) – Add applicable costs per Section 2.3D. e) OH/UG route and civil infrastructure drawings provided by Proposer. f) Civil infrastructure (pads, MH/HHs, conduits, etc.) is designed, procured, and installed by Proposer.		

Item	Description	Cost
g) Includes review of Proposer civil infrastructure designs and materials and inspection of Proposer civil infrastructure construction. h) Does not include vegetation clearing, grading, dewatering, permitting or land rights.		

D. Line Extensions and Upgrades

The costs in Section 2.3D are typical per unit costs for T&D line extensions using typical assumptions based on the Company's current standards and practices. Costs are for Proposer-Build projects.

46kV (O‘ahu)

Item	Description	Cost
160	Additional 100ft 46kV OH Line Extension	$3,300 each
161	Additional 100ft 46kV UG Line Extension	$5,700 each
165	46kV overbuild on existing accessible 12kV (200ft spans)	$1,293,000 / mile
166	46kV overbuild on existing inaccessible 12kV (250ft spans)	$2,191,000 / mile
170	Upgrade existing 46kV OH lines (250ft spans, accessible)	$744,000 / mile
Notes: a) Costs provided are in 2022 dollars. b) OH/UG route and civil infrastructure drawings provided by Proposer. c) Civil infrastructure (pads, MH/HHs, conduits, etc.) designed, procured, and installed by Proposer. d) Does not include vegetation clearing, grading, dewatering, permitting or land rights. e) Includes Company costs for Company-responsible items – See Section 3. f) Items 160 and 161 should be added to the T&D baseline costs for each additional 100ft of Proposer-Build OH or UG line that does not involve Company‘s existing energized facilities. Includes review and inspection of Proposer design/construction. g) Items 165 and 166 includes Company costs to design/construct an OH line extension above Company's existing energized facilities and assumes all poles need to be replaced. h) Item 170 includes Company costs to reconductor an existing Company line to a larger size as determined by the SIS and assumes no poles need to be replaced.		

138kV (O‘ahu)

Item	Description	Cost
175	Additional 100ft OH Line Extension	$5,000 each
176	Additional 100ft UG Line Extension	$7,000 each
180	Overbuild on existing accessible 46kV (400ft spans, 2-556.5 AAC)	$6,190,000 / mile
183	Upgrade existing OH lines (400ft spans, accessible)	$1,231,000 / mile
Notes: a) Costs provided are in 2022 dollars. b) OH/UG route and civil infrastructure drawings provided by Proposer.		

Item	Description	Cost
c) Civil infrastructure (pads, MH/HHs, conduits, etc.) designed, procured, and installed by Proposer. d) Does not include vegetation clearing, grading, dewatering, permitting or land rights. i) Includes Company costs for Company-responsible items – See Section 3. j) Items 175 and 176 should be added to the T&D baseline costs for each additional 100ft of Proposer-Build OH or UG line that does not involve Company's existing energized facilities. Includes review and inspection of Proposer design/construction. k) Item 180 includes Company costs to design/construct an OH line extension above Company's existing energized facilities and assumes all poles need to be replaced. l) Item 183 includes Company costs to reconductor an existing Company line to a larger size as determined by the SIS and assumes no poles need to be replaced.		

E. Service Power

Section 2.3E provides typical requirements and costs for distribution-level service power to the Proposer's facility and/or the proposed Company switching station. Execution of a proposal letter provided by Company in response to Proposer's electrical service request, and separate from the Interconnection Agreement, will be required for service power.

Service power to the Proposer's facility shall emanate from an existing distribution line via new Company overhead and/or underground facilities to the Proposer's service connection point.

For 138kV interconnections, primary station service power requires a line extension and a separate padmount transformer at the proposed Company switching station. Proposer is responsible for providing a backup station power source.

Item	Description	Cost
188	Facility or Station Service Power • Includes 100ft UG 12kV line extension of two (2) feeders and one (1) padmount transformer and assumes no switchgear is required	$84,000 each
189	Distribution OH accessible (200ft spans, #1/0 AAC)	$719,000 / mile
190	Distribution OH underbuild accessible (200ft spans, #1/0 AAC)	$441,000 / mile
191	Distribution OH inaccessible (250ft spans, #1/0 AAC)	$1,469,000 / mile
192	Distribution UG double feeder (200ft spans, #2 AL XLPE)	$1,048,000 / mile
193	Distribution 3ph double riser w/ fuses (including pole/anchor)	$41,000 each
Notes: a) Costs provided are in 2022 dollars. b) OH/UG route and civil infrastructure drawings provided by Proposer. c) Civil infrastructure (pads, MH/HHs, conduits, etc.) is designed, procured, and installed by Proposer. d) Does not include vegetation clearing, grading, dewatering, permitting or land rights. e) Includes engineering, materials, construction labor for electrical work, and inspection for UG civil infrastructure.		

Item	Description	Cost
f) OH line extension – Add applicable costs per Items 189-191. g) UG line extension (if > 100ft) – Add costs per Item 192. h) Additional OH/UG transitions – Add costs per Item 193. i) OH assumes wood poles and 3ph overhead conductor with neutral underbuild. j) Item 190 assumes no poles need to be replaced. k) Accessible assumes vehicles can be used during construction. l) Inaccessible assumes helicopters are needed during construction.		

For 46kV interconnections, the cost for primary and backup station power is included in the Substation baseline costs in Section 2.1B and assumes distribution-level service is not needed or preferred for station power.

2.4 – PROJECT MANAGEMENT BASELINE COSTS

Section 2.4 provides typical Project Management costs for interconnection projects which require a dedicated project manager. The total costs will be dependent on the Proposer's schedule and durations for engineering, construction, and testing/closeout.

A. Not Used

B. Subtransmission Projects

Item	Description	Cost
196	Engineering Phase • Includes facilitation, coordination, and support for Engineering Design and Procurement periods	$18,300 / month
	Construction Phase • Includes facilitation, coordination, and support from the start of construction through back feed (energization)	$23,000 / month
	Testing/Closeout Phase • Includes facilitation, coordination and support for Developer system testing and CSAT	$11,700 / month
Notes: a) Costs derived using 2022 rates. b) Total costs are tied to schedule and duration of the entire project. c) The Closeout Phase shall extend 4 months past GCOD.		

C. Transmission Projects

Item	Description	Cost
197	Engineering Phase • Includes facilitation, coordination, and support for Engineering Design and Procurement periods	$18,300 / month

Item	Description	Cost
	Construction Phase • Includes facilitation, coordination, and support from the start of construction through back feed (energization)	$23,000 / month
	Testing/Closeout Phase • Includes facilitation, coordination and support for Developer system testing and CSAT	$11,700 / month
Notes: a) Costs derived using 2022 rates. b) Total costs are tied to schedule and duration of the entire project. c) The Closeout Phase shall extend 4 months past GCOD.		

2.5 – TYPICAL TELECOMMUNICATIONS REQUIREMENTS AND COSTS

Section 2.5 provides typical telecommunications requirements and costs for interconnection projects. The communications equipment will require a communications channel(s). Some options include lease line, fiber, or microwave.

A. Not Used

B. Variable Projects ≥ 1 MW and ≤ 3 MW

1. Primary communications links can consist of lease line, licensed radio, fiber, or microwave.
2. Back-up communications links are optional (can consist of lease line, licensed radio, fiber, or microwave).
3. Additional analog leased telephone lines are required to support revenue meters (Proposer shall do their own due diligence for costs on this).

C. Variable Projects > 3 MW

1. Primary communications links can consist of lease line, fiber, or microwave.
2. Back-up communications links are required (can consist of lease line, licensed radio, fiber, or microwave).
3. Back-up communications links must be transport diverse until the "last mile" for projects greater than 10MW.
4. Additional analog leased telephone lines are required to support revenue meters (Proposer shall do their own due diligence for costs on this).
5. Project shall be capable of providing SCADA communications to both primary and backup System Operation Control Centers.

D. Firm Projects

1. Primary communications links must be Company-owned fiber or microwave.

2. Back-up communications links are required (can consist of leased line or Company-owned fiber or microwave).
3. For interconnection to a new Company switching station, primary and back-up communications links must be transport diverse, with a minimum separation of 6 feet, to the new Company switching station.
4. For interconnection to an existing Company switching station, primary and back-up communications links must be transport diverse, with a minimum separation of 6 feet, from the existing Company switching station to the Proposer's substation.
5. Additional analog leased telephone lines are required to support revenue meters (Proposer shall do their own due diligence for costs on this).
6. Project shall be capable of providing SCADA communications to both primary and backup System Operation Control Centers.

E. Projects Interconnecting to a Company Switching Station

1. If Proposer's substation is not adjacent to the proposed Company switching station, then Proposer is responsible for providing the communications links between the two (2) sites.
    a. If Proposer chooses to run fiber between the sites, Proposer will own the fiber from their site up to a splice box immediately outside of the Company switching station ("meet point"). Company will own fiber from the meet point to the termination into the Company switching station – See Item 220.
    b. All UG infrastructure will be designed, procured, and constructed by Proposer.
    c. If interconnection is to a new Company switching station, a communications cabinet may be required at both sites – See Item 202.
    d. If interconnection is to an existing Company switching station, a new communications cabinet will be required at the Proposer's substation and may be required at the existing Company switching station – See Item 202.
2. If Proposer's substation is adjacent to the proposed Company switching station, no additional Company costs are anticipated to be required for the Proposer's substation.

F. Telecommunications Baseline Costs

The costs below are high level per unit costs for communications requirements in support of the Project. Sections 2.5A through 2.5E above provide typical scenarios of when these options may be utilized.

Communications Cabinet or Enclosure

Item	Description	Cost
201	Communications Cabinet with circuits to support SCADA (Projects $\geq$ 1 MW and $\leq$ 3 MW) • Projects with SCADA and DTT but no diverse communication circuits	\$164,000 / site
202	Communications Cabinet with circuits to support SCADA, Relay Protection, monitoring devices, etc.	\$192,000 / site

Item	Description	Cost
	• Projects with SCADA, DTT, and diverse communication circuits	

Notes:
a) Costs provided are in 2022 dollars.
b) All projects that require communications will require facilities to store the communications equipment. The examples above are provided but other alternatives may be available upon request.
c) Cabinet is used to support Company equipment and capable of providing communications circuit for SCADA, DTT, monitoring devices, etc.
d) Communications cabinet cost does not include fiber, microwave equipment or lease circuits.
e) Proposer will provide all conduits, foundations, HHs, AC power, grounding as required per Company standards.

Lease Line Options

Item	Description	Cost
205	Lease Line one-time and recurring costs	Will vary based on 3rd party provider

Notes:
a) Add cost of Communications Cabinet – See Items 201-202.
b) Check with Company to understand the current lease line requirements.
c) Communication circuit requirements will be based on applications needed for the project.
d) Company can provide communication circuit interconnection requirements and assist with review of circuit order from the 3rd party provider as needed.
e) Proposer to work directly with 3rd party provider if a lease line circuit is needed.
f) Cost will be the responsibility of the Proposer and is to be negotiated with the 3rd party provider.

Fiber-Optic Cable Option

Item	Description	Cost
210	New Fiber-only pole line (200' avg spans, 60-strand ADSS) • Includes new wood poles	$312,000 / mile
211	Fiber underbuild on new or existing pole line (200' avg spans, 60-strand ADSS) • Assumes no replacements of existing poles are needed	$166,000 / mile

Notes:
a) Costs provided are in 2022 dollars.
b) Add cost of Communications Cabinet – See Items 201-202.
c) Assumes no splices are needed along the route.

Microwave Option

Item	Description	Cost
215	Point-to-Point Microwave Link • Includes 2 each antenna equipment to create a radio link	$697,000 / link
216	50ft Microwave Tower	$612,000 each
217	100ft Microwave Tower	$888,000 each

Notes:

a) Costs provided are in 2022 dollars.
b) Add cost of Communications Cabinet – See Items 201-202.
c) Assumes there is radio line-of-site clearance between the communication endpoints.
d) Assumes FCC licensed microwave frequencies are available.
e) Assumes there are existing structures/buildings with space available on both ends to house the radio equipment.
f) Assumes Telecommunications grounding standards are up to date at both sites.
g) Assumes 48 V DC power with 12-hour battery backup is available.
h) Does not include special site-specific permit/approval activities that may be required including, but not limited to, Neighborhood Board(s), Conservation District Use Application, Environmental Assessment, Shoreline Management Area approval, biological (endangered species or habitat) surveys, and/or cultural (archeological) surveys or the cost of any migration required for approvals to be granted. Proposers should conduct their own due diligence for these costs.
i) Assumes space is available at both ends to construct antenna towers or structures that are rated to survive a Saffir-Simpson category 4 hurricane.
j) Other options for Microwave Towers of varying heights may be available.

Projects Interconnecting to a Company Switching Station Only

Item	Description	Cost
220	Fiber from "meet point" to termination in Company switching station • Assumes 24-strand fiber cable. • Includes splicing, termination, and testing work. • Civil infrastructure (HHs, conduits, etc.) is designed, procured, and installed by Proposer.	$31,000

Notes:

a) Costs provided are in 2022 dollars.
b) Required if the Proposer's substation is not adjacent to the Company switching station per Section 2.5E.
c) Assumes the "meet point" is within 500ft of the termination in the Company switching station.

2.6 – TYPICAL SECURITY REQUIREMENTS AND COSTS

Section 2.6 provides typical security requirements and costs for new facilities installed as a part of the interconnection. Security requirements and costs can vary based on many factors including, but not limited to, location, crime rate, environment, aspects of the surrounding area, terrain, accessibility, layout of the facility, etc. The specific requirements for each facility will be subject to final review during the design and engineering phase. Additional information, including the Company's Physical Security Strategy, is available upon request after execution of an NDA with the Company.

A. Proposer Responsibilities at Proposer Facility

The Proposer shall be responsible to incorporate security components and systems for **their facilities** that consider the Security Guidelines for the Electricity Sector (CIP-014-2): Physical Security, as published by the North American Electric Reliability Corporation (NERC) and that at a minimum, meet the requirements below.

For Company-owned facilities within the Proposer's Facility, Company requires:

1. Standard 8ft high security fence with 3-strand barbed wire V-top.
2. Interior mounted 4' high cattle fencing.
3. All gates will be secured using a proprietary padlock system.
4. Proposer-owned cabinets/enclosures housing Company equipment shall be secured with a lock provided by Company.
5. Company requires 24/7 access to Company facilities within the Proposer facility.

B. Proposer Responsibilities for New Company-Owned Substations

Company-owned substations interconnecting firm generation typically require high levels of security due to the critical role they play in the Company's system which may include, but is not limited to:

1. <u>Camera Monitoring</u> – Proposer to procure and install all camera mounts and cameras. Specific models required for cameras, mounts, caps, and other associated hardware will be provided to Proposer after an NDA is executed with the Company. Company's Security Integrator will terminate cables, adjust, and optimize as needed.
2. <u>Electronic Card Access System</u> – For control & microwave houses, Proposer procures/mounts card access devices and installs any cables necessary. Company Security Integrator will terminate cables and program and test devices and peripherals.
3. <u>Infrastructure</u> – Conduits and associated electrical and junction boxes shall be installed by the Proposer as a part of the substation site development. Conduits shall be rigid PVC, dedicated for Security systems purposes only, and sealed properly from the origin to the termination point.
4. <u>Cabling</u> – Cabling shall be installed by the Proposer as a part of the substation site development and shall be of the type specified below for the applicable voltage. Company's Security Integrator will terminate both ends.
   a. 69kV Substations – CAT 5E
   b. 138kV Substations – CAT 6
5. <u>Integrator</u> – Company's Security Integrator will procure the server and necessary switches, terminate all ends, program the server, and set all fields of view for all camera shots.

6. Fencing – Schedule 40 galvanized fence post and fence fabric is required for fencing. The fencing shall be 8 feet high with heavy gauge support wire along the length of the bottom. 3-strand barbed wire shall be mounted atop the fence at a 45-degree angle on the inside and outside for the entire length of fence and gates.
7. Locks – All gates shall be secured using a proprietary padlock system. Company will provide physical padlocks for gates and electrical equipment.
8. Lighting – Motion and static lighting are necessary for additional safety and security deterrent measures and to enhance camera viewing at night. Proposer shall procure and install all lighting as a part of the substation site development. Motion LED lighting arrays shall be placed on all corners and entrances. Static LED lighting arrays shall be placed on the control house and throughout the yard to meet required lighting levels. Lighting shall be Dark Sky compliant.
9. Perimeter Intrusion Detection (138kV only) – Proposer shall procure and install devices and cables using a contractor that is trained and qualified to install the specified system. Company's Security Integrator will terminate cables, program, and test system. The specific models for the system will be provided to Proposer after execution of an NDA with the Company.

The costs below are the Company costs for the Company-responsible items above.

Item	Description	Cost
251	Substation Security	$104,000 / site

Notes:

a) Costs provided are in 2022 dollars.
b) Includes Company costs for internal labor, materials, and contractors to support design, installation, programming, and testing of all security systems.
c) Location has flat terrain, is accessible, and is rural with a moderate to low crime rate and little to no homeless population.
d) Fire break is not needed.

SECTION 3 – PROPOSER-BUILD RESPONSIBILITIES

Section 3 defines Company and Proposer responsibilities for Proposer-Build interconnections.

3.1 – COIF AT PROPOSER SITE

Company will perform the following:

1. Review and approval of Proposer drawings and material selection.
2. Inspect Proposer construction.
3. Programming and functional testing of digital devices (i.e., DFR, RTU, etc.).
4. Terminate wiring between RTU and IPP interface cabinet.
5. Perform acceptance testing.
6. Procurement, installation, and testing of revenue meters.

Proposer is responsible for the following:

1. Design, procurement, and construction of:
    a. All COIF except what is identified above.
        i. Pull wiring between RTU and IPP interface cabinet and coil up on both ends.
    b. All civil infrastructure (conduits, equipment pads, etc.) at the Proposer facility.
2. As built drawings prior to acceptance testing.

3.2 – COIF AT EXISTING COMPANY-OWNED SUBSTATIONS

Company will perform all engineering, material procurement, and construction at existing Company-owned substations except as described below.

1. For a 138kV OH termination into an existing substation, Proposer is responsible for design, procurement, and construction of the OH T&D facilities from the project site up to and including the last pole/foundation before the substation termination structure.
2. For a 138kV UG termination into an existing substation, Proposer is responsible for design, procurement, and construction of the UG T&D lines and associated civil infrastructure up to the termination on the riser structure.

3.3 – T&D LINE WORK

Company will perform the following:

1. Review and approve Proposer drawings.
2. Inspection of Proposer construction.
3. Design, procurement, and construction of electrical facilities for the final tap at the GCP.
4. Design, procurement, and construction of electrical facilities within the existing Company right-of-way (i.e., where Company's energized facilities are).
5. Procurement does not include the conductors or cable required for the last span as discussed below.
6. Break into Company's existing UG facilities for interception point (i.e., at an existing MH/HH/vault)

Proposer is responsible for the following:

1. Route design of the OH or UG lines (locations of poles, MHs, HHs, vaults, conduits, equipment, etc.).
2. Design, procurement, and construction of:
    a. All civil infrastructure (vaults, manholes, conduits, equipment pads, etc.) between the Proposer facility and the GCP.
    b. All electrical facilities from the Proposer facility up to and including the last pole or manhole/vault prior to existing Company facilities.
3. For OH to existing OH final tap

   a. Coil enough OH conductor on the last pole for Company to string and terminate the last span of conductor to the GCP.
4. For UG tap to existing OH final tap
   a. Stub-up the riser conduit above ground level at the bottom of the riser pole.
   b. Pull cable to the last MH/HH/vault prior to the riser.
   c. Provide enough cable for Company to make the last pull up the riser and terminate the cables.
5. For UG tap to existing UG
   a. Conduits to connect to interception point provided by Company.
   b. Pull cable to the last MH/HH/vault prior to intercepting Company’s existing facilities.

3.4 – TELECOMMUNICATIONS

Company will perform the following:
1. Review and approval of Proposer drawings.
2. Design, procurement, installation, and testing of network equipment such as routers, multiplexers and associated hardware required at Proposer Site, Company Switching Station and/or Remote Substation Facilities to provision circuits required for the project.
3. Design, procurement, and installation of fiber termination equipment within Company owned or managed facilities at Proposer Site, Company Switching Station and/or Remote Substation Facilities, as needed, to support the communication requirements.
4. Design, procurement, and installation of microwave radio within Company owned or managed facilities at Proposer Site, Company Switching Station and/or Remote Substation Facilities, as needed, to support the communication requirements.

Proposer is responsible for the following:
1. Preparation of drawings related to the installation of telecommunication equipment to be turned over for Company ownership and/or Company management, including telecommunications cabinets and/or racks and telecommunications power.
2. Design, procurement, and installation of telecommunications cabinets and/or racks at the Proposer site and/or Company Switching Station to support the telecommunications equipment, as well as supporting equipment including air conditioning, alarming equipment, ground bars and fuse panels.
3. Design, procurement, and installation of equipment at the Proposer site and/or Company Switching Station to support telecommunications power requirements, including, but not limited to, batteries, battery racks, rectifiers, and distribution panels.
4. Design, procurement, and installation of fiber cable, as needed, to support communications requirements, including SCADA connection from the Developer’s RTU to the Company’s RTU.
5. Ordering and installation of leased services, as needed, to support communications requirements.

3.5 – SECURITY

Responsibilities for Proposer-Build projects are the same as for Company-Build projects. See Section 2.6 for those responsibilities.

SECTION 4 – TYPICAL COMPANY DURATIONS FOR INTERCONNECTION PROJECTS

The tables below in Section 4 are to be used as a reference when developing an overall project schedule to assist Proposers in setting realistic durations and deadlines for critical milestones. These tables represent typical durations for the Company to complete the listed critical milestones that assist in moving the interconnection project through the IRS, Engineering, Procurement, and Construction phases. The durations below do not include time for Proposer to complete items they are responsible for. These high-level typical durations are for planning purposes only and is not intended to cover all project specific requirements. Specific project details can increase or decrease these durations. The detailed project schedule will be determined after the IRS is completed.

4.1 – NOT USED

4.2 – SUBTRANSMISSION PROJECTS

Milestone	Duration Proposer-Build	Notes
IRS Phase		
Model Validation	1 month	May increase depending on # of iterations
System Impact Study (SIS)	150 calendar days	Following Model Acceptance
Facility Study (FS)	40 business days	Following completion of SIS, SLD Acceptance, and Receipt of Developer Drawings and Schedules
Engineering Phase		
30% Design & Review	20 business days	
60% Design & Review	20 business days	Following 30% Design acceptance.
90% Design & Review	20 business days	Following 60% Design acceptance
Issued for Construction (IFC) Design & Review	20 business days	Following 90% Design acceptance.
Procurement Phase		
Procurement	N/A	Procurement of materials typically happens at 60% design completion
Construction Phase		
Construction	N/A	Based on scope/complexity of work
Acceptance Testing	25 business days	Approximately 3 weeks after construction completion
CSAT	30 business days	To occur after commissioning of Proposer's Facility. Duration depends on Proposer's ability to meet the Performance Standards.
Notes		

Milestone	Duration Proposer-Build	Notes
a) For Proposer-Build projects, the Engineering Phase includes design reviews of Proposer designs for COIF and review of SOIF supporting/impacting COIF. b) N/A indicates that the task is the responsibility of the Proposer in a Proposer-Build project.		

4.3 – TRANSMISSION PROJECTS

Milestone	Duration Proposer-Build	Notes
IRS Phase		
Model Validation	1 month	May increase depending on # of iterations
System Impact Study (SIS)	150 calendar days	Following Model Acceptance
Facility Study (FS)	40 business days	Following completion of SIS, SLD Acceptance, and Receipt of Developer Drawings and Schedules
Engineering Phase		
30% Design & Review	20 business days	
60% Design & Review	20 business days	Following 30% Design acceptance.
90% Design & Review	20 business days	Following 60% Design acceptance
Issued for Construction (IFC) Design & Review	20 business days	Following 90% Design acceptance.
Procurement Phase		
Procurement	N/A	Procurement of materials typically happens at 60% design completion
Construction Phase		
Construction	N/A	Based on scope/complexity of work
Acceptance Testing	25 business days	Approximately 3 weeks after construction completion
CSAT	30 business days	To occur after commissioning of Proposer's Facility. Duration depends on Proposer's ability to meet the Performance Standards.
Notes		
a) For Proposer-Build projects, the Engineering Phase includes design reviews of Proposer designs for COIF and review of SOIF supporting/impacting COIF. b) N/A indicates that the task is the responsibility of the Proposer in a Proposer-Build project.		

4.4 – ADDITIONAL DURATIONS TO INTERCONNECT AT AN EXISTING SUBSTATION

Milestone	Duration Company-Build	Notes
Engineering Phase		
30% Design & Review	40 business days	
60% Design & Review	50 business days	Following 30% Design acceptance.

Milestone	Duration Company-Build	Notes
90% Design & Review	50 business days	Following 60% Design acceptance
Issued for Construction (IFC) Design & Review	30 business days	Following 90% Design acceptance.
Procurement Phase		
Procurement	Up to 24 months	Procurement of materials typically happens at 60% design completion and after PUC approval. Material lead times dependent on manufacturer availability.
Construction Phase		
Construction	Up to 12 months	Duration increases up to 12 months for larger sized projects. Construction to begin after procurement completion.
Notes		
a) The durations listed are in addition to the durations listed in Section 4.2 and 4.3 b) The Engineering Phase includes Company design & review of Company-Owned Interconnection Facilities (COIF) & reviews of Proposer-Owned Interconnection Facilities (SOIF) supporting/impacting COIF.		

PROJECT EXAMPLES - APPENDIX H UNIT COST TABLE

Examples provided for illustrative purposes only and is not binding for actual facility costs.
Estimated costs represent Company costs charged to the Proposer.

Projects interconnecting to subtransmission

Example 1

15MW variable project interconnecting to an existing 46kV OH circuit per Attachment 2 of this Appendix H. The line extension includes an OH to OH tap to the existing line, 0.1 miles overbuild on existing 12kV lines, and 300ft of new 46kV OH lines to the Proposer substation. All lines are accessible. Company will complete the OH to OH final tap and the overbuild. Proposer to construct the new OH lines between the termination structure and the last pole before the tap to the overbuild portion. DTT and sync/deadline check required at 1 remote sub. No T&D line upgrade work needed. Company to install 0.1 miles of ADSS fiber (underbuild) to the Proposer substation and install Company-owned equipment in Proposer-provided communications cabinet. Proposer to provide leased line telecommunications with a 3rd party provider for backup communications. Assumed durations: Engineering = 12 months, Construction = 10 months, Testing/closeout = 6 months.

Appx H Item	Description	Quantity	Unit	Unit Price ($)	Total Cost ($)
15	46kV Variable Project	1	EA	$403,000	$403,000
21	Remote substation work	1	EA	$435,000	$435,000
120	46kV OH to OH (1st tap)	1	EA	$86,000	$86,000
165	46kV overbuild on 12kV	0.1	MI	$1,293,000	$129,300
160	Additional 100ft OH Line Extension	3	EA	$3,300	$9,900
	46kV OH line extension (by Proposer)	1	LS	$0	$0
196	Project Management - Engineering	12	MO	$18,300	$219,600
196	Project Management - Construction	10	MO	$23,000	$230,000
196	Project Management - Testing/Closeout	6	MO	$11,700	$70,200
202	Comm Cabinet	1	EA	$192,000	$192,000
211	Fiber underbuild	0.1	MI	$166,000	$16,600
205	Backup Leased line (by Proposer)	1	LS	$0	$0
			ESTIMATED TOTAL =		**$1,791,600**

Example 2

50MW firm project interconnecting to two (2) paralleled 46kV circuits. Proposer will construct a new 46kV Company-owned substation per Attachment 3 of this Appendix H. Proposer will construct a line extension of two circuits from the new substation up to the last pole before the taps. One line extension is 900ft OH and the other is 800ft OH and 100ft UG (not including the 100ft span at the tap). The second line tap is at a riser (OH to UG type). Company will complete the final taps. Relay upgrades required on one of the circuits. Company to install fiber from nearest splice point to the new substation (0.5 miles) underbuilt on existing lines for primary communications. Proposer provides a leased line for backup communications. Assumed durations: Engineering = 12 months, Construction = 10 months, Testing/closeout = 6 months.

Appx H Item	Description	Quantity	Unit	Unit Price ($)	Total Cost ($)
16	46kV Firm Project	1	EA	$1,041,000	$1,041,000
22	Remote Sub Work	1	EA	$561,000	$561,000
120	46kV OH to OH (1st tap)	1	EA	$86,000	$86,000
121	46kV OH to UG (2nd tap)	1	EA	$188,000	$188,000
160	Additional 100ft OH Line Extension	17	EA	$3,300	$56,100
161	Additional 100ft UG Line Extension	1	EA	$5,700	$5,700
	46kV line extensions (by Proposer)	1	LS	$0	$0
	46kV civil infrastructure (by Proposer)	1	LS	$0	$0
	New 46kV substation (by Proposer)	1	LS	$0	$0
196	Project Management - Engineering	12	MO	$18,300	$219,600
196	Project Management - Construction	10	MO	$23,000	$230,000
196	Project Management - Testing/Closeout	6	MO	$11,700	$70,200
202	Comm Cabinet	1	EA	$192,000	$192,000
211	Company fiber underbuild (primary)	0.5	MI	$166,000	$83,000
205	Backup Leased line (by Proposer)	1	LS	$0	$0
252	Security	1	EA	$104,000	$104,000
			ESTIMATED TOTAL =		**$2,836,600**

Projects interconnecting to transmission

Example 3

100MW firm project interconnecting to existing 138kV OH circuits. Proposer to build a new Company-owned 4-bay BAAH switching station per Attachment 4 of this Appendix H. Line extension includes interception of existing circuits and a 1500ft extension of four (4) new 138kV OH lines to new Company switching station (not including the 100ft spans at the tap). All lines are accessible. Proposer to construct the new OH lines between the termination structures at the substation and the last poles/structures before intercepting the existing lines. Company will construct the final tap from the last poles/structures to the GCP. Line relay upgrades are required for both circuits and a breaker replacement is required on one circuit. Company to install 0.25 miles of ADSS fiber (underbuild) to the new Company switching station and install Company-owned equipment in Proposer-provided communications cabinet; back-up communications is required. Proposer to provide leased line for backup telecommunications. Proposer's substation is adjacent to Company's switching station. Assumed durations: Engineering = 18 months, Construction = 10 months, Testing/closeout = 6 months.

Appx H Item	Description	Quantity	Unit	Unit Price ($)	Total Cost ($)
COIF Costs Paid by Proposer					
32	Company work at new substation	1	EA	$2,105,000	$2,105,000
36a	Line relay upgrades	2	EA	$452,000	$904,000
36b	Breaker replacement	1	EA	$569,000	$569,000
133	138kV OH to OH Final Tap	2	CKT	$962,000	$1,924,000
175	Additional 100ft OH Line Extension	60	EA	$5,000	$300,000
197	Project Management - Engineering	18	MO	$18,300	$329,400
197	Project Management - Construction	10	MO	$23,000	$230,000
197	Project Management - Testing/Closeout	6	MO	$11,700	$70,200
	138kV OH line extension (by Proposer)	1	LS	$0	$0
202	Comm Cabinet	1	EA	$192,000	$192,000
205	Leased line (by Proposer)	1	LS	$0	$0
211	Company fiber underbuild (primary)	0.25	MI	$166,000	$41,500
250	Company security costs	1	LS	$104,000	$104,000
			ESTIMATED TOTAL =		**$6,769,100**

Example 4

200MW firm generation project interconnecting at Hoohana substation. The 142MW SPOF limit means project requires two (2) gen-tie lines to Hoohana from the Proposer's site. The first termination requires adding a termination to an existing bay. The second termination requires expansion of the substation for two (2) additional BAAH bays (less 1 breaker), a new control house, and interconnecting the Kahe-Halawa 2 circuit to Hoohana. Proposer to run two (2) OH gen-tie lines (1,000ft each, not including 100ft span into sub) from Proposer's site to Hoohana. First gen-tie into Hoohana will be overhead, and Company to string final OH span from last pole to termination structure at Hoohana. Second gen-tie will be underground to cross existing 138kV lines (500ft not including 100ft span into sub), and Proposer to terminate at Hoohana. Proposer to run fiber between Proposer's substation and Hoohana since substation is not adjacent to Hoohana. A comm cabinet is required at the Proposer's substation. Assumed durations: Engineering = 18 months, Construction = 10 months, Testing/closeout = 6 months.

Appx H Item	Description	Quantity	Unit	Unit Price ($)	Total Cost ($)
1st Termination					
41	Company work at Proposer's substation	1	EA	$408,000	$408,000
44	Add termination to existing bay	1	EA	$1,151,000	$1,151,000
2nd Termination					
42	Expansion of substation	2	EA	$500,000	$1,000,000
43	Add BAAH bay w/ 1 termination	2	EA	$2,975,000	$5,950,000
44	Add termination to existing bay	1	EA	$1,151,000	$1,151,000
46	New control house	1	EA	$2,000,000	$2,000,000
47	Interconnect Kah-Hal #2 to Hoohana	1	LS	$3,557,000	$3,557,000
Gen-tie Lines					
175	Gen-tie 1 - Add'l 100ft OH Line Extension	10	EA	$5,000	$50,000
135	138kV OH Final Span to Existing Sub	1	EA	$100,000	$100,000
175	Gen-tie 2 - Add'l 100ft OH Line Extension	10	EA	$5,000	$50,000
176	Gen-tie 2 - Add'l 100ft UG Line Extension	5	EA	$7,000	$35,000
136	138kV UG Termination to Existing Sub	1	EA	$34,000	$34,000
	138kV civil infrastructure (by Proposer)	1	LS	$0	$0
197	Project Management - Engineering	18	MO	$18,300	$329,400
197	Project Management - Construction	10	MO	$23,000	$230,000
197	Project Management - Testing/Closeout	6	MO	$11,700	$70,200
202	Comm Cabinet (at Proposer's sub)	1	EA	$192,000	$192,000
220	Fiber from "meet point" to sub	1	EA	$31,000	$31,000
	Fiber civil infrastructure by Proposer	1	LS	$0	$0
251	Company security costs	1	LS	$104,000	$104,000
			ESTIMATED TOTAL =		**$16,442,600**

Electrical service to Proposer Facility

Example 5

Proposer requests service from existing 12kV line 0.5 miles away from the facility (new OH line for 0.4 miles and 0.1 miles underbuilt on the Company-owned interconnection lines). The OH line risers down and 2 feeders will serve a padmount transformer 100ft away from the riser pole. Proposer to install civil infrastructure (ductlines, MH/HH/vaults, equipment pads, etc.).

Appx H Item	Description	Quantity	Unit	Unit Price ($)	Total Cost ($)
188	Padmount tsf for facility service	1	EA	$84,000	$84,000
189	12kV OH accessible	0.4	MI	$719,000	$287,600
190	12kV OH underbuild	0.1	MI	$441,000	$44,100
193	12kV 3ph riser	1	EA	$41,000	$41,000
	12kV civil infrastructure (by Proposer)	1	LS	$0	$0
			ESTIMATED TOTAL =		**$456,700**

Electrical service to Proposer Facility and Primary station service for Company-owned switching station

Example 6

Proposer requests service from existing 12kV line 0.2 miles away from the facility. Line extension is a new OH accessible line. The OH line riser down and 2 feeders will serve a padmount transformer 100ft away from the riser pole. Primary station service for the Company-owned switching station will be tapped off of the facility service line extension, riser underground, with 2 feeders going to a padmount station service transformer in the switching station located 300ft away from the tap point. Proposer to install civil infrastructure (ductlines, MH/HH/vaults, equipment pads, etc.).

Appx H Item	Description	Quantity	Unit	Unit Price ($)	Total Cost ($)
188	Padmount tsf for station service	2	EA	$84,000	$168,000
189	12kV OH accessible (facility service)	0.2	MI	$719,000	$143,800
193	12kV 3ph riser (facility service)	1	EA	$41,000	$41,000
193	12kV 3ph riser (station service)	1	EA	$41,000	$41,000
192	UG dbl feeder (station service)	0.04	MI	$1,048,000	$39,697
	12kV civil infrastructure (by Proposer)	1	LS	$0	$0
			ESTIMATED TOTAL =		**$433,497**

DRAFT

REQUEST FOR PROPOSALS

FOR

RENEWABLE DISPATCHABLE GENERATION

AND

ENERGY STORAGE

ISLAND OF O‘AHU

DECEMBER 22, 2022

Docket No. 2017-0352

Appendix I – O‘ahu Near-Term Grid Needs Assessment Update

Hawaiian Electric

July 29, 2022

The Honorable Chair and Members
of the Hawai'i Public Utilities Commission
Kekuanao'a Building, First Floor
465 South King Street
Honolulu, Hawai'i 96813

Dear Commissioners:

Subject: Docket No. 2017-0352 – To Institute a Proceeding Relating to a Competitve Bidding Process to Acquire Dispatchable and Renewable Generation
Docket No. 2018-0165 – Instituting a Proceeding to Investigate Integrated Grid Planning
Updated O'ahu and Maui Island Near Term Grid Needs Assessment

In accordance with Ordering Paragraph No. 2 of Order No. 38479,[1] issued on June 30, 2022 in the subject proceeding, the Hawaiian Electric Companies[2] respectfully submit the attached July 29, 2022 *O'ahu Near-Term Grid Needs Assessment* and *Maui Near-Term Grid Needs Assessment* as Attachment 1 and Attachment 2, respectivley. This report describes the methodology and inputs used to study scenarios whose results were then used to inform recommendations for Grid Needs for solution sourcing for the Stage 3 Request for Proposals ("RFP") for O'ahu and Maui Island, which the Companies plan to discuss at the RFP stakeholder conference through a virtual meeting scheduled for August 5, 2022 from 1:00 to 3:00 pm HST. A virtual meeting invitation has been emailed to Integrated Grid Planning participants and the competitive bidding distribution list. Other interested parties may contact OahuRenewableRFP@hawaiianelectric.com for meeting information. A recording of the meeting and presentation slides will be posted at https://www.hawaiianelectric.com/clean-energy-hawaii/selling-power-to-the-utility/competitive-bidding-for-system-resources/stage-3-oahu-rfp when available.

The Companies look forward to working with the Commission, the Independent Observer, and stakeholders to finalize the RFP and launching a competitive and successful procurement.

[1] Ordering Paragraph No. 2 of Order No. 38479 provided: "The HECO Companies shall file an updated Near-term Grid Needs Assessment for Oahu and Maui Island within 30 days of this Order[.]"

[2] "Hawaiian Electric Companies" or "Companies" are Hawaiian Electric Company, Inc., Hawai'i Electric Light Company, Inc., and Maui Electric Company, Limited.

Sincerely,

/s/ Marc Asano

Marc Asano
Director, Integrated Grid Planning

Enclosure

c: Service List

Hawai'i Powered

O'ahu Near-Term Grid Needs Assessment

JULY 2022

Hawaiian Electric

Contents

List of Figures

1 EXECUTIVE SUMMARY

Hawaiian Electric's Climate Change Action Plan to reduce greenhouse gases 70% from 2005 levels by 2030 is bold and ambitious, setting Hawaiʻi on a track to achieve net zero carbon emissions economywide by 2045. The path to a more sustainable Hawaiʻi is rooted in our clean energy vision, Hawaiʻi Powered: Clean energy for Hawaiʻi, by Hawaiʻi. It's about working with everyone – stakeholders, communities, customers, and employees, together – to find the right solutions to create an affordable, sustainable, reliable and resilient energy system for future generations. Achieving a decarbonized economy while balancing these objectives is the challenge that lies before us.

The changing nature in the way customers consume electricity and adopt new technologies like electric vehicles and battery energy storage, along with customers' increased reliance on electricity to power their daily routine necessitates a different approach to grid reliability, identification of grid needs, and acquisition of the right solutions. With the "clean" economy having greater reliance on electric supply, customers will expect reliable and resilient electric service with less tolerance for even short duration outages. These are the complex engineering problems to be solved.

There are also interrelated, near-term issues that must be addressed. First, an issue that Hawaiʻi residents are all too familiar with – volatile oil prices that drive much of the energy economy; highlighted by the recent Russia-Ukraine conflict. Next, an issue that threatens to become systemic – a fleet of 70-year-old generators that has far outlived its original designed life with decreasing availability over the past decade because of their age and the manner in which they are now operated. As more intermittent sources of energy are integrated onto the grid, these generators can no longer operate at a steady pace 24 hours a day, seven days a week. Instead, they are being asked to jog, sprint, start and stop on a daily basis. Environmental regulations and compliance will also necessitate new types of flexible and base-loaded firm generation in the future.

This report establishes a roadmap to get us there, showing how we can reduce carbon emissions and fossil-fuel consumption, improve generation reliability and diversify the renewable energy portfolio to better withstand climate-related or extreme events.

In developing this roadmap, Hawaiian Electric performed technical analyses grounded in the following objectives:

- Add new low-cost variable renewable energy to further decarbonize the electricity sector and reduce fossil-fuel use
- Improve generation reliability through the careful replacement of existing firm generation with the right mix of variable renewables and energy storage backed by renewable firm generation
- Diversify the resource portfolio to be more resilient despite weather-dependent generation
- Modernize aging generation infrastructure (a fleet with more flexible resources to complement wind, solar and battery energy storage projects)
- Acquire more flexibility for the current and future generation system (building on the renewable dispatchable solar generation and aggregated grid service resources acquired to date)

The key findings of the grid needs assessment include:

- Reductions in greenhouse gas emissions and fossil-fuel use can be achieved through continued additions of customer and grid-scale low-cost, zero-emission generation resources like solar and wind. This includes distribution system enhancements and eventual creation of renewable energy zones and new transmission infrastructure to integrate higher amounts of grid-scale renewable resources, which should be pursued in collaboration with communities, landowners and renewable energy developers.
- Flexible customer resources such as private rooftop solar, distributed energy storage, electric vehicles, and energy efficiency measures play a central role in reducing carbon emissions and reducing supply side energy and capacity needs. By 2030, this includes approximately 1,000 gigawatt hours of energy efficiency (GWh), 250 megawatts (MW) of private rooftop solar and 150 MW / 400 MWh of customer battery energy storage.
- Over the next five years, at least 544 GWh of grid-scale renewable energy should be procured, leveraging existing infrastructure to facilitate quicker interconnection. Producing greater amounts of renewable energy will require development of renewable energy zones.
- Modernizing the firm generation fleet along with new variable renewable and energy storage resources will improve generation reliability. The addition of 500-700 MW of renewable firm generation is needed to meet expected greater demand due to electrification of transportation and buildings and reduce the probability of generation outages while improving operational flexibility to better integrate variable renewable generation. This addition of renewable firm generation could allow for the removal or deactivation of up to 930 MW of older, less flexible fossil-fuel generation by 2033.
- A diversified energy portfolio that includes renewable firm power additions creates a more resilient generation system to better withstand and/or recover from climate-related and extreme events, which are increasing in frequency and can significantly affect generation output.

We must urgently address these needs through a balanced portfolio of renewable resources including customer resources, renewable firm generation alongside renewable dispatchable energy resources such as wind, solar and battery energy storage.

The near-term needs of the grid

The grid needs assessment identified commercially available renewable resources and technologies that would cost-effectively ensure near-term reliability on Oʻahu. In the near-term Hawaiian Electric will rely upon technologies such as wind, solar, battery energy storage, advanced inverters and renewable firm generation. This grid needs assessment follows the integrated grid planning (IGP) process to assess Oʻahu's grid needs based on:

- Capacity expansion optimization analysis to add new least-cost resources
- Reliability assessment of the system
- Validation of future system operations through production cost simulations.

The detailed reliability assessment included a probabilistic resource adequacy evaluation that incorporated a methodology consistent with industry best practices, reviewed and supported by the technical advisory panel (TAP), an independent group of technical experts from utilities, market operators and research organizations that meets periodically to consult with Hawaiian Electric on the IGP process and the more technical aspects of our transition to 100%

renewable energy. The resource plans for the scenarios considered in this assessment are included in Section 6.3 and Section 9.1 for reference.

The assessment considered a range of future scenarios bookended by two possible futures: One where load dramatically increases due to electric vehicle growth (i.e., "high load scenario") and one where load decreases due to high customer adoption of efficiency measures like light-emitting diode (LED) lighting, heat pump water heaters and distributed energy resources (i.e., "low load scenario"). Across this range of scenarios, the optimal resource mix includes low-cost renewable energy that may include grid-scale solar, land-based and offshore wind, and battery energy storage.

Customer technologies play a central role in all pathways to 2030 and beyond. Significant amounts of customer-implemented energy efficiency and private rooftop solar and storage will reduce grid-scale resource needs. These resources have the potential to provide the desired flexibility to enable efficient grid operations and meet needs for electric vehicle charging. Hawaiian Electric and its industry partners will need to continue aggressive pursuit of these resources through programs, pricing and procurements. Further analysis in this area will continue throughout the IGP process.

Firm Generation

In this report, firm generation refers to a synchronous machine based technology that is available at any time under system operator dispatch for as long as needed, except during periods of outage and deration, and is not energy limited or weather dependent.

Low-cost renewables backed by renewable firm generation continues to be the optimal resource option over the next decade. The remaining technical land-based wind potential on O'ahu is selected in year 2027 because of its high capacity factor and low assumed resource cost per kWh of renewable energy. Starting in year 2030, depending on the load scenario, varying amounts of solar paired with storage (hybrid solar) are built and reach the maximum solar land potential in the later years of the planning horizon. A large tranche of hybrid solar that resides in the lower-cost transmission renewable energy zones is selected in 2030 – in the Base scenario, nearly 1,600 MW of hybrid solar is selected, with the majority built on land with a slope greater than 15%. Of that 1,600 MW, 958 MW is located on land with less than 15% slope. The resource mix also includes renewable firm generation sources, powered by renewable fuels, that are critical to ensuring grid reliability when solar, wind and storage resources have lower production. Firm generation additions are generally timed slightly ahead of the removal of fossil-fuel generation to maintain generation reliability and are operated primarily as stand-by generation during periods of low renewables. In total, less renewable firm generation is being added than the amount of fossil generation that is deactivated because future capacity needs are increasingly met through the capacity contributions of other renewable resources such as wind and solar. The pace and quantity of these renewable resources will depend on customer trends, the way residential and commercial customers choose to consume energy over the coming years, including the number of electric vehicles on the road, the time of day the vehicles are charged, the amount of rooftop solar and battery energy storage customers install, and the energy efficiency measures that are adopted.

In a future where land is limited to develop renewable energy projects, more renewable firm generation sources will be needed. In this scenario, no new land-based wind or biomass projects are allowed to be selected and grid-scale solar is limited to an additional 270 MW. All 270 MW of grid-scale hybrid solar is built and greater amounts of firm generation is needed compared to the Base scenario. Over the longer term, offshore wind becomes an important resource in achieving 100% renewable energy along with distributed solar.

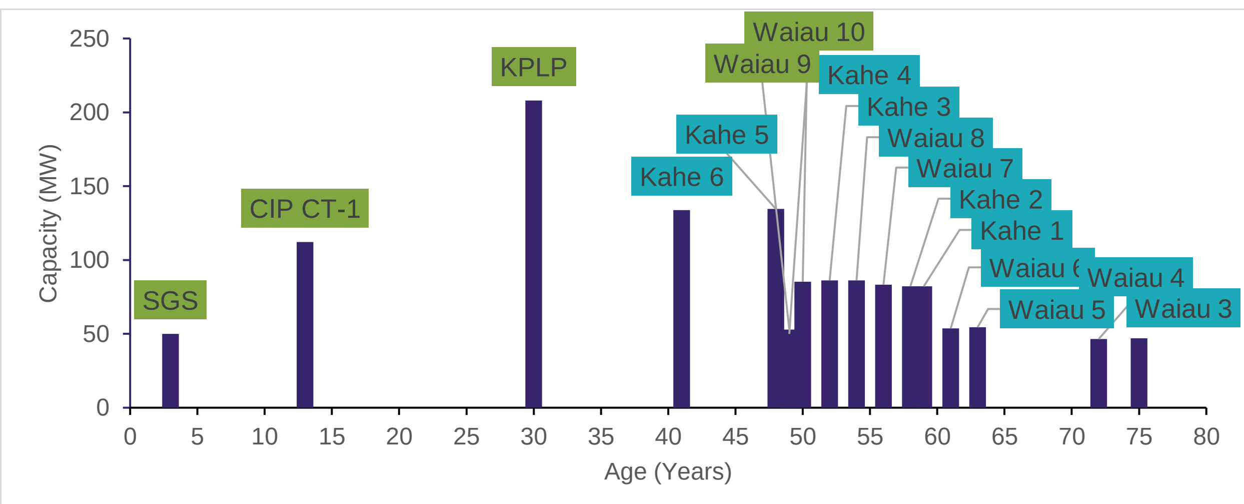
Resource Adequacy

Hawaiian Electric performed an extensive reliability analysis, guided by the reliability objectives that were prioritized by the IGP stakeholder council, a wide-ranging group representing community, government, environmental and business interests. Regular council meetings and feedback ensure stakeholder input and engagement throughout the IGP process. The stakeholder council's top three reliability objectives are: Evaluating the cost of different levels of reliability, generation resource diversity and planning reliability for extreme events. The stakeholder council had agreed that the utility should provide steady, adequate and generally affordable energy to customers in most circumstances.

In tandem with the stakeholder council's reliability objectives, reliability analyses found that significant amount of DER and DR resources (incremental 2030 customer resource additions relative to 2021 levels include 145 MW / 1,014 GWh of energy efficiency, 29 MW / 183 GWh of electric vehicles, and 253 MW / 423 GWh of private rooftop solar), between 270 MW and 1,600 MW grid-scale renewable resources, and 300-500 MW firm renewable generation by 2029 and another 200 MW by 2033 provides the optimal portfolio of resources to assure a reliable system and mitigate reliability risks in the near term. The combination of these resources also provide other benefits in modernizing the generation system such as the ability to quickly start up, ramp up and respond to fluctuations in wind and solar resources. The total near-term addition of 500-700 MW of renewable firm generation could potentially facilitate the removal or deactivation of 930 MW of utility and independent power producer (IPP) fossil-fuel generation.

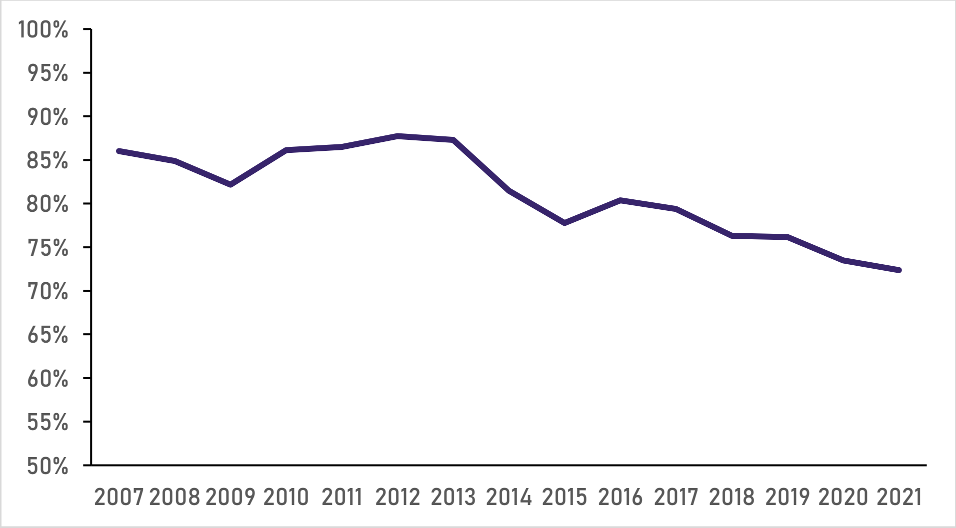
Reliability risks have been increasing over the past decade. Figure 1 illustrates the aging generation fleet that has served O'ahu residents over the past 70 years. These units are in urgent need of replacement, as they are currently being operated beyond their intended lifespan.

Figure 1. Age of existing generation fleet on O'ahu



But as shown in Figure 1 and Figure 2, old age coupled with higher stress operation since the onset of variable renewable energy has caused the generation fleet to become increasingly unreliable. The fleet needs to be retooled and modernized with newer, cleaner forms of firm energy.

Figure 2. Historical availability of Hawaiian Electric's generation fleet



The typical North America reliability guidelines for loss of load expectation (LOLE) are 0.1 days per year. The Australian Energy Market Operator uses reliability criteria that limits annual expected unserved energy (EUE) to 0.002% or less. These metrics provide a useful frame of reference when evaluating the LOLE and EUE of resource plans that consider different additions of variable renewables and firm generation resources. More stringent reliability guidelines may be warranted to address generation resilience on isolated island grids as high-impact, low frequency events increase in frequency.

In assessing system reliability through 2030, the analyses found that:

- Forced outages (and increasing unavailability of fossil-fuel generators) is a principal driver of reliability, especially when considering more recent trends in generator unit availability.
- 200 – 400 MW of new flexible firm generation alongside 270 – 1,600 MW of new hybrid solar in 2029 results in LOLE of 0.01 – 0.08 days per year and EUE of 0.01 – 0.09 GWh per year, indicating compliance with established resource adequacy standards used by other jurisdictions.
- Under a high load scenario that includes higher levels of electric vehicle (EV) growth that is consistent with state decarbonization policy, more than 400 MW of new firm generation is needed to achieve resource adequacy.
- While adding 1,600 MW of hybrid solar in 2029 improves reliability, 175 – 200 MW of firm generation is still needed to meet reliability standards.
- All resources considered in the resource adequacy analyses contribute to the reliability of the system. These include supply side resources like firm thermal generators, short and long duration energy storage, land-based wind, offshore wind, and hybrid solar as well as demand-side resources like distributed PV and energy efficiency. A diverse resource portfolio is important when planning for the future grid to avoid over-reliance on any one resource to meet resource adequacy.

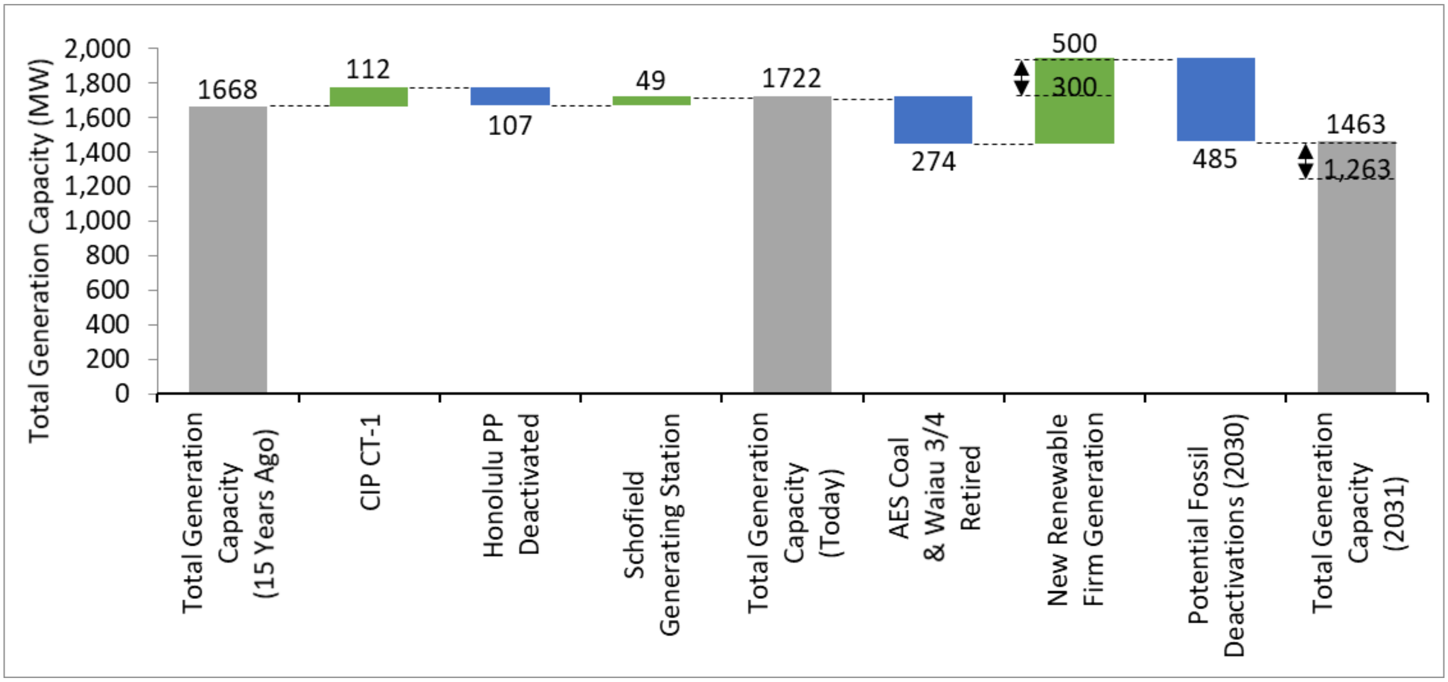
Hawaiian Electric conducted a thorough review of a probabilistic resource adequacy analysis that evaluated recent trends in generation outages and low and high amounts of future hybrid solar. This review found that 300 MW by 2029 and another 200 MW by 2033 is a minumum starting amount of new firm renewable generation that may improve reliability to an acceptable range of 0.10 days per year LOLE or better and limits EUE to 0.002%. However, a higher amount of firm generation in the range of 400 or 500 MW by 2029 could be needed to account for several future risks and uncertainties. These risks include a Land Constrained scenario where lower amounts of hybrid solar and no future land-based wind are added, higher loads, remaining fossil-fuel generation fleet further declining in performance, or where environmental concerns or lack of spare parts may hasten the retirement of existing generators.

Renewable dispatchable generation in combination with renewable firm generation is needed now to enable a reliable decarbonized electric economy

The 300 MW to 500 MW renewable firm generation by 2029 target accomplishes the reliability objectives set out by the stakeholder council and is based on rigorous technical analyses as described in this report. While a target of 500 MW of renewable firm generation may be interpreted as acquiring "excess" capacity in certain future scenarios, decarbonization efforts in other sectors of the economy is expected to lead to rapid load growth, such as in the high electrification load scenario. The conventional tendency is to procure the "just right" and "just in time" amount of capacity that meets near-term needs. ***However, the uncertainty surrounding the rapid transformation to a decarbonized economy through electrification, climate change impacts, significant shifts in the energy resource mix and customer adoption of new technology warrants a strategic shift in electric system reliability and resilience planning, one that positions Hawaiian Electric to rapidly respond to a rapidly changing environment.***

Hawaiian Electric has planned for this transition over the past 15 years and is now entering a new phase of that transition with the integration of new hybrid solar facilities. With the new hybrid solar projects acquired through recent procurements and additional resources expected in future procurement, significant fossil-fuel capacity could be deactivated, conditioned upon new renewable firm resources coming online, as shown in Figure 3.

Figure 3. Projected firm generation capacity timeline



The supply of electricity in the next few years and over the next 30 years will be heavily dependent on least-cost, weather-dependent resources that can contribute to traditional reliability needs and reduce reliance on firm fossil-fuel generation. However, overreliance on weather-dependent resources and battery energy storage will not provide the reliability (and resilience) needed to withstand severe weather periods or natural disasters that could damage grid-scale solar, wind or private rooftop solar systems. Renewable firm generation will diversify the energy portfolio and create a more resilient generation system by providing energy when other resources may be unavailable. As customers become increasingly reliant upon electricity through the electrification of transportation and buildings, system reliability and resilience must be increased. The 300-500 MW of new firm capacity by 2029 and an additional 200 MW of new firm capacity by 2033 will reduce reliability and resilience risks against a range of futures that were analyzed. For example, 700 MW of new firm generation would provide some assurance of maintaining system reliability if load rapidly grows over the next decade due to electric vehicle growth as forecasted in the high load scenario (more firm generation will likely be needed in this scenario). In the Land Constrained scenario where only a limited amount of land is available for future solar development, new firm units will be used more often to ensure the load can be served.

In summary, procuring at least 300 MW and up to 500 MW by 2029 and an additional 200 MW by 2033 of renewable firm generation is a least-regrets target to maintain and improve reliability against a range of uncertain futures.

Acquisition of a diverse and reliable resource portfolio

While all-source and technology-neutral procurements are pursued whenever possible, such procurement may not yield the most diverse and resilient portfolio in this case. Without a specific target for renewable firm generation, a technology-neutral procurement will likely yield more hybrid solar projects as recent procurements suggest, resources which are indeed needed to achieve decarbonization goals. However, to encourage diversification, reduce reliability risks and increase resilience of the generation system, a procurement with a specific renewable firm generation target is warranted. As the reliability analysis demonstrated (Section 6.5), a significant amount of additional hybrid solar without new firm generation would not be sufficient to meet a targeted reliability range; thus, firm generation is needed.

The acquisition of additional low-cost solar, wind and energy storage resources alongside renewable firm generation will reduce fossil-fuel usage. To that end, and consistent with the findings of this report, procuring renewable dispatchable generation alongside firm generation will allow renewable firm generation to operate fewer hours per year but play a critical role in operating during periods of poor sun or wind conditions, providing quick-starting capability and offline reserves during contingency events.

Procuring firm renewable generation also addresses the increasing reliability risk of an aging, inflexible generation fleet with flexible resources to facilitate the integration of more wind, solar and energy storage resources. By necessity, the existing fossil-fuel generation fleet is being operated at lower minimum loads and cycling more than it was designed to do. As more hybrid solar projects are integrated over the next few years, these inflexible steam generation units will be strained under increasingly variable operations. Operating the 55- to 75-year-old fleet in this manner only accelerates the aging process, which has led to and will continue to cause increasing rates of forced outages and more deration of firm capacity on a daily basis. These reliability risks must be urgently addressed—this is foundational to achieving the state's decarbonization and renewable energy goals.

Hawaiian Electric is once again at the forefront of the industry through its recent procurements to integrate hybrid solar plants at unprecedented levels relative to the size of the system. There will be a lot to learn from operating these hybrid plants over the next five to 10 years; particularly how batteries are best used to improve reliability and resilience. There are many issues that remain (i.e., pace of electrification, availability of existing firm generation, land constraints, community acceptance, performance of grid-forming inverters for stability, supply chain issues, among others), and we must be prepared for increasing risks throughout the industry.

Hawaiian Electric has made significant progress in integrating wind, solar and energy storage resources and more is expected. But this cannot be done at the expense of reliability, which will have far greater economic and societal consequences for the state. If fossil-fueled firm generation is not replaced with new flexible firm generation, there will be a limited ability to integrate more low-cost intermittent renewable energy in the future, resulting in an increased burden on underserved communities.

For example, new flexible generators have lower minimum operating points and can quickly ramp up and down, start and stop multiple times a day. New generators also have significantly higher availability and reliability. These benefits allow more low-cost renewable energy to be utilized at much higher levels than if the current fleet of inflexible fossil-fuel generation remains in service. Higher utilization of low-cost renewable energy will mean a lower electric bill burden on customers; disproportionately

- Continue to displace fossil-fuel through acquisition of low cost, low carbon renewable energy, starting with 544 GWh through the Stage 3 RFP in Docket No. 2017-0352
- Continue to pursue customer adoption of DER through new programs and advanced rate design, consistent with the outcomes of the DER Docket No. 2019-0323
- Pursue generation modernization as soon as practicable to improve operational flexibility and mitigate present reliability risks. Firm renewable generation needs include 300-500 MW of in 2029, and another 200 MW in the 2033 timeframe, starting with the Stage 3 RFP in Docket No. 2017-0352
- Pursue development of renewable energy zones to facilitate interconnection of additional renewable energy
- Consider procurement of energy efficiency to accelerate adoption in amounts up to the forecasted target to reduce supply side needs.
- Continue to pursue managed EV charging programs, time-of-use rates, DER, and energy efficiency.
- Incorporate system security and system stability analyses as part of IGP, which may yield additional resource needs to mitigate risks associated with a high-renewable energy system.
- Pursue procurement(s) as part of the IGP solution sourcing process to determine market for long lead renewable resources such as offshore wind and renewable energy zones to increase resource diversity and mitigate land use risks.

affecting customers that do not have access to or the means to invest in technologies to offset their own electricity usage. Continuation of the current fossil-fuel generation fleet will mean increased likelihood of outages and volatile energy prices. Ultimately, generation modernization today keeps the state on track to achieving its policy goals which include 100% renewable energy, a balanced portfolio of resources, cost-effective electricity, decarbonization of transportation and other sectors, and resilience against extreme weather events.

2 INTRODUCTION

The 2021 international summit on climate change made clear that the actions we take this decade will determine whether humanity can slow or stop the warming of the planet. To support this global effort, Hawaiian Electric announced a bold Climate Change Action Plan centered on reducing carbon emissions by as much as 70% by 2030 compared to 2005 levels and reaching net-zero carbon emissions by 2045. Reducing carbon emissions by more than two-thirds over this decade will be a stretch. We know it's achievable and if everyone pitches in, we'll create a cost-effective, sustainable and resilient energy system for future generations. This commitment by Hawaiian Electric is a significant down payment on the economy-wide reduction the State of Hawai‘i will need to achieve to align with the U.S. commitment to reduce carbon emissions by at least 50%.

In setting out pathways to achieve those goals, Hawaiian Electric conducted this grid needs assessment – a living roadmap intended to guide efforts by the company, customers, stakeholders, project partners and communities to realize deep decarbonization across the economy with an emphasis in the electric sector. The integrated grid planning (IGP) process as well as other energy efforts will continue to build and refine "what is needed" to eventually meet the state's goal of net negative carbon emissions by 2045.

To guide the development of the grid needs assessment, Hawaiian Electric leveraged the IGP process and incorporated feedback from the IGP stakeholder council, technical advisory panel and stakeholder technical working group (STWG). The process, methods, criteria, inputs and assumptions and feedback incorporated are documented in Hawaiian Electric's *August 2021 Inputs and Assumptions* review point filing, its subsequently approved *March 2022 Inputs and Assumptions* filing and its *November 2021 Grid Needs Assessment and Solution Evaluation Methodology* review point. As a result, the inputs, assumptions and methodologies used in this report are among the most transparent planning processes in the industry, with stakeholder and expert recommendations incorporated along the way.

The stakeholder council's role in advising Hawaiian Electric has been instrumental in guiding the grid needs assessment. The stakeholder council has focused on three key areas: community engagement, reliability and resilience. Key highlights in these three areas are discussed below, and the incorporation of the stakeholder council's feedback is noted throughout this report.

Community Engagement

The stakeholder council made the following recommendations to improve community engagement in the IGP and procurement processes:

- There are three "branches" that need public participation, input and guidance: Hawaiian Electric, the Public Utilities Commission (PUC) and developers. Public participation is also needed from other key stakeholders, such as the Hawai‘i State Energy Office.
- Hawaiian Electric should raise the "floor" of stakeholder engagement: defining and raising the bar for minimum requirements of successful engagement.
- Customization is key, as different communities have different interests. It's critical to listen and understand each community's needs and objectives. For example, the Kunia community is concerned about agriculture. The North Shore community may be interested in education and job creation for the community related to the renewable project.

- The PUC has a role to play in soliciting community input. Look for ways for the PUC to be more open and accessible to the public and provide public notice of dockets outside of the current process, such as through news releases. The PUC should solicit input on RFPs throughout the RFP process rather than only at the end when projects are already selected.
- Be more proactive in soliciting input during RFP development. Reach community members via newspapers, website, social media, neighborhood newsletters, etc. Broaden the type of stakeholders who provide input beyond just energy "insiders" who are involved in the industry on a day-to-day basis.
- Consider "co-design" of concepts in RFP development similar to what is being done on Molokaʻi. Start the engagement process in Step 1, not Step 5.
- Identify available sites for development and work with neighborhoods and communities on siting projects there prior to RFP issuance.
- Better demonstrate to communities how feedback is being taken into account.

Specific Recommendations and Changes Hawaiian Electric Proposes to Make to the IGP and Procurement Process

Across many different initiatives, Hawaiian Electric has heard the desire of communities to play a more engaged role early in the renewable energy development process. Hawaiian Electric continues to engage communities around the islands as it develops RFPs and identifies future grid needs, while leveraging the various tools for communication that incorporate many of the concepts put forward by the stakeholder council. Building upon the outreach to stakeholders and communities in developing recent RFPs, Hawaiian Electric will continue to listen, learn and work with communities throughout the process of developing the next round of RFPs on Oʻahu and other islands.

What outreach tools will Hawaiian Electric use?

Over the next year, we will use virtual and in-person outreach tools to share information with the public and gather input. These tools include:

Online participation site

Hub for up-to-date information and community feedback, with interactive maps, comment form and survey questions.

Briefings with community organizations

Offering presentations at existing community meetings, either virtually or in person.

Community talk stories

Smaller, informal in-person or virtual conversations with community members to share information and discuss Hawaiʻi's energy future.

Public meetings

Broad public meetings with presentations, Q&A sessions, and opportunities to share input.

We will tailor our outreach tools and strategies to meet the unique needs of each island.

One key way Hawaiian Electric proposes to incorporate stakeholder council recommendations and past community feedback is to expand community engagement requirements for prospective projects by further specifying requirements for community engagement with more detailed guidance and by adding a requirement that developers provide a benefits package for the surrounding and affected communities.

Hawaiian Electric proposed to require project developers to commit to financial community benefits. Developers will be required to set aside at least $3,000 per MW (of their proposed project) per year for community benefits. These funds would be donated for actions and/or programs aimed at addressing specific needs identified by the host community, or to a 501(c)(3) not-for-profit community-based organization(s) to directly address host community-identified needs. The developers would provide a documented community benefits package highlighting the distribution of funds for Hawaiian Electric's review. This document will be made public on each project's website and demonstrate how funds will directly address needs in the host community.

The community benefits package would also include documentation of each project developer's community consultation and input collection process to define community needs, along with actions and programs aimed at addressing those needs. Preference would be given to projects that commit to setting aside a larger amount or commit to providing other benefits (including but not limited to creating local jobs, payment of prevailing wages or improving community infrastructure).

In addition, Hawaiian Electric has also included the following modifications to the procurement process in response to community feedback:

- Higher scoring to project proposals that are proposed on land zoned commercial, industrial, land with greater impervious cover, or reclaimed land;
- Procedural improvements were made to further ensure the protection and preservation of cultural resources;
- Prioritization of local labor and prevailing wage for proposed projects; and
- Additional requirements for developers to provide monthly updates to the community prior to and throughout the construction process.

Reliability

The stakeholder council discussed generation reliability and considerations in forward-looking planning. The council developed a core goal of reliability: to ensure a steady, adequate and generally affordable energy to customers, almost all of the time. Through a robust discussion, the stakeholder council prioritized their top three reliability objectives in support of the core goal:

- Evaluate cost of higher levels of reliability
- Diversify generation resources
- Plan for extreme events

Based on those objectives, the stakeholder council considered various capabilities and strategies to meet those objectives. Common themes included:

- Reliability for Tier 1 customers (i.e., the most critical customers defined in the Resilience Working Group Report and shown in Figure 4) should be a priority
- An evaluation of reliability contributions of different generation technologies (i.e., solar, wind, energy storage, firm generation, etc.)
- Define and clarify terminology—for example, firm generation, non-firm generation, hybrid solutions. Firm generation is not perfect and could also be affected by fuel supply and forced outages.
- The role of microgrids and how they can support grid reliability and resilience.
- Customer solutions for reliability
- Harden the transmission and distribution (T&D) system—for example, hardening of poles, wires and other critical equipment
- Investigate future technologies like green hydrogen

Some of these capabilities and objectives are also grid resilience considerations (i.e., the role of microgrids, T&D hardening and planning for extreme events), while others have been brought to the technical advisory panel (TAP) for recommendations. Hawaiian Electric addresses or incorporates these objectives and capabilities within this report. For example, the reliability contributions of different generation technologies and the subject and definition of firm generation are issues that have been extensively discussed with the TAP and addressed through the resource adequacy analyses provided in Section 6. A discussion of customer solutions for reliability is discussed in Section 6.1. Planning reliability for extreme events is intertwined with resilience; however, a discussion of inclusion of extreme events in reliability planning is discussed in Section 6.5.10.

Resilience

The IGP resilience working group and stakeholder council provided recommendations and considerations for incorporating resilience into grid planning. The working group built consensus on a definition of resilience and adopted the commission's definition in the performance-based regulation docket, "Resilience is the ability of a system or its components to adapt to changing conditions and withstand and rapidly recover from disruptions." For the grid, this means the ability to anticipate, absorb, adapt to, and rapidly recover from a catastrophic event. Stakeholders defined the following objectives for resilience:

- Reduce the likelihood of power outages during a severe event
- Reduce the severity and duration of any outages that do occur during and after a severe event
- Reduce restoration and recovery times following a severe event
- Return critical infrastructure customers' power rapidly to enable mutual support and recovery during an emergency
- Return all customers within appropriate times
- Limit environmental impacts of a severe event

The following threat scenarios were prioritized by the working group to guide the IGP process and other resilience initiatives, and by key customers and critical infrastructure partners in developing resilience preparations.

- Hurricane/floods/high wind events
- Tsunamis and earthquakes
- Wildfire
- Physical and cyber attack
- Volcano (Hawaii Island)

As shown in the figure below, the working group recommended three different customer tiers to prioritize for enhancing resilience. The identification of customer groups represents stakeholders' views of the prioritization of customers with the greatest need to be returned to service quickly. These priorities should also be coordinated with other agencies for alignment on restoration priorities.

Figure 4. Resilience working group recommended customer classifications by tier

Tier 1	Tier 2	Tier 3
• Military • Telecommunications • Hospitals and critical healthcare • Water and wastewater • Emergency management and first responders	• Transportation • Hospitality • Banking and finance	• Remaining customers

Since 2015, the Governor has issued at least 15 different emergency proclamations relating to hurricanes, tropical storms, flooding, landslides, wildfire, and lava events. A common theme that emerged during the working group and stakeholder council discussions raised that resilience should be considered in reliability planning because it's a matter of "when, not if" a weather-related event threatens the reliability of the grid. A lot more work is needed within the resilience area; however, in Section 6, initial elements of resilience are being incorporated within the reliability analysis consistent with the recommendations stated herein. However, Hawaiian Electric expects to continue to refine its resilience analysis as more discussions occur and additional information becomes available.

Guiding Principles

Hawai‘i is at a much different place in its grid transformation and decarbonization efforts than any other state. Over the next few years, O‘ahu, Hawai‘i Island, and Maui County are collectively expected to reach 50% renewable generation with a combination of wind, solar, geothermal, hydro, biomass/waste-to-energy, battery energy storage and private rooftop solar. This means the islands will rely on a much higher percentage of variable resources than other states to contribute to ensuring a reliable energy system. It is essential that integrated grid planning is considered across all aspects of the community and grid including distribution, transmission and generation resources. Additionally, customers must appropriately benefit from costs incurred to advance the state's policies and related investments. Hawaiian Electric relies upon a set of renewable energy planning principles in developing its roadmap and action plan.

Guiding Principles

Renewable energy is the first option. We are pursuing cost-effective renewable resource opportunities that reduce carbon emissions and stabilize customer bills. Getting off imported fossil-fuels removes Hawaiʻi from the volatility of world energy markets and gives future generations a tremendous advantage. It can also create a clean energy research and development industry for our state.

The energy transformation must include everyone. Electricity is essential. Our plans, as well as public policy, should ensure access to affordable electricity, with special consideration given to low-to-moderate-income households. Meaningful community participation must be a key element of renewable project planning.

The lights have to stay on. Reliability and resilience of service and quality of power is vital for our economy, for our national security, and for critical societal infrastructure. Our customers expect it, deserve it and pay for it. Our plans must maintain or enhance the resilience of our isolated island grids by relying on a mix of resources and technologies.

Today's decisions must be open to tomorrow's breakthroughs. Our plans keep the door open to developments in the rapidly evolving energy space. We must be able to easily accept new, emerging, and breakthrough technologies that are cost-effective and efficient when they become commercially viable.

The power grid needs to be modernized. Energy distribution is rapidly moving to the digital age. We are reinventing our grid to facilitate a decarbonized energy portfolio and to enable technologies such as demand response, dynamic pricing, aggregation and electrification of transportation.

Our plans must address climate change. Our Climate Change Action Plan has set a goal to reduce carbon emissions from power generation 70% by 2030 compared with 2005 levels. Our resilience strategy aims to minimize the impacts of climate change — rising sea levels, coastal erosion, increased temperatures and extreme weather events — on the energy system.

There's no perfect choice. No single energy source or technology can achieve our clean energy goals. Every choice has an impact, whether it's physical or financial. While we can mitigate those impacts, attaining our clean energy goals has major implications for our land and natural resources, our economy and our communities. We seek to make the best choices by engaging with community members, regulators, policy makers and other stakeholders.

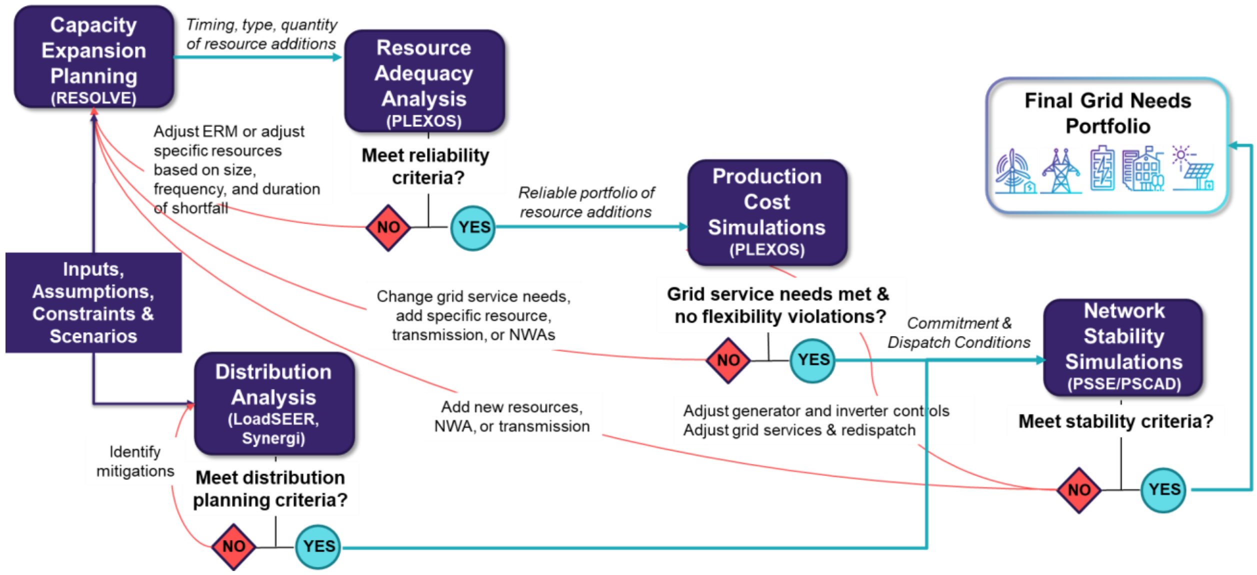
This report is organized as follows:

- Sections 3, 4 and 5 describe the methodology in assessing grid needs, the inputs and assumptions used in the various technical analyses and the scenarios that were analyzed in forming the near-term roadmap and next steps.
- Section 6 describes the results of the grid needs analysis. The majority of the report focuses on near-term reliability needs within the context of long-term resource plans over a number of potential future scenarios.
- Section 7 describes production cost simulations and operations under the procurement resource plan, showing the simulated dispatch of resources on the system.
- Section 8 describes the near-term next steps and action plan.

3 METHODOLOGY

Hawaiian Electric used the analytical framework developed in the IGP process to identify the grid needs for near-term solutions sourcing. As shown in Figure 5, multiple tools were used to determine the grid needs.

Figure 5. Grid Needs Assessment methodology



This grid needs assessment (GNA) focuses on the first three steps of the GNA methodology to assess near-term capacity expansion planning, resource adequacy and production cost simulations based on the March 31, 2022 and August 2021 IGP Inputs and Assumptions as described in Section 4. The methodology to identify grid needs is described in Hawaiian Electric's November 2021 Grid Needs Assessment & Solution Evaluation Methodology review point (GNA Methodology Report). The IGP process ongoing in Docket No. 2018-0165 will build upon this GNA, including the approved *IGP Inputs and Assumptions* filed on March 31, 2022, and the remaining analytical steps – network stability and distribution analysis.

> **Grid Needs** means the specific grid services (including but not limited to capacity, energy and ancillary services) identified in the grid needs assessment, including transmission and distribution system needs that may be addressed through a Non-Wires Alternative.

RESOLVE was used to provide directional grid needs detailing the optimal type, quantity and timing of resource additions across various scenarios based on a range of constraints such as pricing (capital cost, fixed cost, variable cost, etc.), operational characteristics (power output, ramp rate, heat rate, etc.) and services offered (provide regulation, meet RPS, etc.). An energy reserve margin analysis was performed in PLEXOS to check the reliability of the various scenarios under study alongside a detailed probabilistic resource adequacy endorsed by the TAP. Finally, a production cost simulation was also performed in PLEXOS to provide a more accurate hourly dispatch of the generating fleet.

3.1 Capacity Expansion (RESOLVE)

The grid needs assessment uses the planning assumptions from the Company's *Inputs and Assumptions* filings summarized in Section 4 to determine a baseline, or "Base" portfolio of grid needs, the Low Load and High Load bookend scenarios and the Land Constrained scenario where the potential to develop future renewable projects is constrained based on limited community approval for new renewable energy development. The portfolios were developed using the RESOLVE and PLEXOS models to identify and verify the grid needs through 2035. The primary objective of this phase of the process was to identify the optimal mix of proxy resources that are built to represent the system's grid needs. RESOLVE is intended to provide directional guidance as to the optimal mix of resources; it is not intended to be a prescriptive pathway that must be strictly followed during solution sourcing activities.

3.2 Resource Adequacy (PLEXOS)

The Resource Adequacy step includes a separate energy reserve margin (ERM) analysis in PLEXOS of each scenario plan developed during the capacity expansion modeling step to determine capacity reliability needs. Additional capacity needs were informed by the unserved energy observed when the net load, plus a 30% margin, was not met by existing resources. The ERM methodology is further described in the GNA Methodology Report, Exhibit 1, Appendix C. Iterations were completed to evaluate varying amounts of firm generation resources to meet the energy reserve margin guideline.

The resource adequacy step also includes a probabilistic analysis consistent with industry best practices, including recommendations Hawaiian Electric adopted from the TAP. The probabilistic analyses evaluate the reliability of the system using five weather years and 50 randomized generator outages for a total of 250 iterations; the results are then used to calculate various reliability metrics including loss of load expectation (LOLE), loss of load events (LOLEv), loss of load hours (LOLH) and expected unserved energy (EUE) to assess reliability.

3.3 Production Cost Simulations (PLEXOS)

The resource plans optimized in RESOLVE and adjusted to meet resource adequacy were then evaluated in PLEXOS, by running an hourly production cost simulation, to verify system operations and dispatch of resources. This provides insight into how the new resources will be operated and dispatched in future years. The system costs of each plan are based on the sales forecast, fuel price forecast and resource cost assumptions described in Section 4. More accurate costs of long-term plans will be developed as part of the solution sourcing process when actual market solutions are proposed with current market pricing.

4 KEY INPUTS TO GRID NEEDS ANALYSIS

The inputs used in this analysis are briefly described below.

4.1 Sales Forecast

Hawaiian Electric utilized the sales forecast in its *August 2021 IGP Inputs and Assumptions* filing. This sales forecast includes updates to its electric vehicle forecast (including the managed and unmanaged charging system profile), customer solar and battery storage forecast and the addition of a time-of-use layer representing non-DER and EV customer participation.

While the inputs and assumptions were not approved by the PUC until modifications were filed on March 31, 2022, the changes to the forecast layers are not considered significant and contained well within the load bookends that were modeled.

4.2 Fuel Price Forecast

Hawaiian Electric utilized the 2021 fuel price forecast in the *March 2022 IGP Inputs and Assumptions* filing approved by the PUC on March 31, 2022. This fuel price forecast was based on the Brent forecast provided by the Energy Information Administration Annual Energy Outlook 2021 (EIA AEO).

4.3 Future Resource Options

RESOLVE is given a variety of resource options to choose from, as shown below in Figure 6, during the development of the capacity expansion plans. Firm resources consist of biomass, combined cycle (CC), combustion turbine (CT), and internal combustion engines (ICE). In this analysis, these resources are assumed to be operating on renewable fuels, such as biodiesel, but a sensitivity analysis was performed where these resources were assumed to be operated on fossil-fuel. Storage includes short and long duration standalone energy storage as well as pumped storage hydro that are grid charge capable resources. Wind resources consist of both land-based and offshore wind. Solar resources consist of both standalone solar PV, hybrid solar (i.e., PV paired with energy storage) where RESOLVE can optimize the storage duration, and residential PV paired with 2 hour distributed BESS that is provided via a DER aggregator. Paired storage must be charged by the source they are paired with and are not grid charge capable.

In addition to being modeled as available candidate resources in RESOLVE, the probabilistic resource adequacy analyses explicitly considered the addition of several of these resources to evaluate their impact to reliability.

- Combustion Turbines – Section 6.5.2 and 6.5.3
- Paired PV+BESS – Section 6.5.1 and 6.5.3
- 12 Hour Duration Energy Storage (Proxy for Pumped Storage Hydro) – Section 6.5.4
- 2 Hour Duration Energy Storage (Proxy for Demand Response) – Section 6.5.8
- Land-based Wind – Section 6.5.1 and 6.5.3
- Offshore Wind – Section 6.5.9

Figure 6. Future resource options for RESOLVE to select

Firm	Storage	Wind	Solar	Distributed Energy Resources (DER)
Steam/Biomass	Standalone Battery Energy Storage System (BESS)	Land-Based Wind	Standalone Solar (PV)	Aggregated Distributed Energy Resources (Distributed Paired Solar)
Combined Cycle (CC)	Pumped Storage Hydro (PSH)	Offshore Wind	Hybrid Solar (Paired PV)	
Combustion Turbine (CT)				
Internal Combustion Engine (ICE)				

4.4 Resource Cost Forecast

The resource cost forecast used to develop the resource plans provided in this analysis is consistent with the *March 2022 Inputs and Assumptions* filing with the exception that we did not apply the cost adders for development of renewables on higher sloped land. The cost adders were not available at the time of this analysis, which was mostly conducted before March 2022, but will be included in future analyses.

4.5 Regulating Reserve Requirement

The regulating reserve requirements were based on the methodology described in Hawaiian Electric's November 5, 2021, *GNA Methodology Report*. This analysis included both the 1-minute and 30-minute regulating reserve requirements.

4.6 Hourly Dependable Capacity for Energy Reserve Margin

The hourly dependable capacity (HDC) for variable renewables was based on the 1-sigma calculation as described in Hawaiian Electric's November 5, 2021, GNA Methodology Report. Hawaiian Electric has since adopted the 80th percentile dependable capacity methodology for renewable resources; however, at the time of this analysis such discussions were still on-going with the technical advisory panel. The use of 1-sigma, however, is substantially similar to the 80th percentile, as discussed at a January 20, 2022 TAP Meeting. Therefore, Hawaiian Electric expects the impact using the 1-sigma approach instead of the 80th percentile to be negligible.

4.7 Variable Renewable Resource Potential

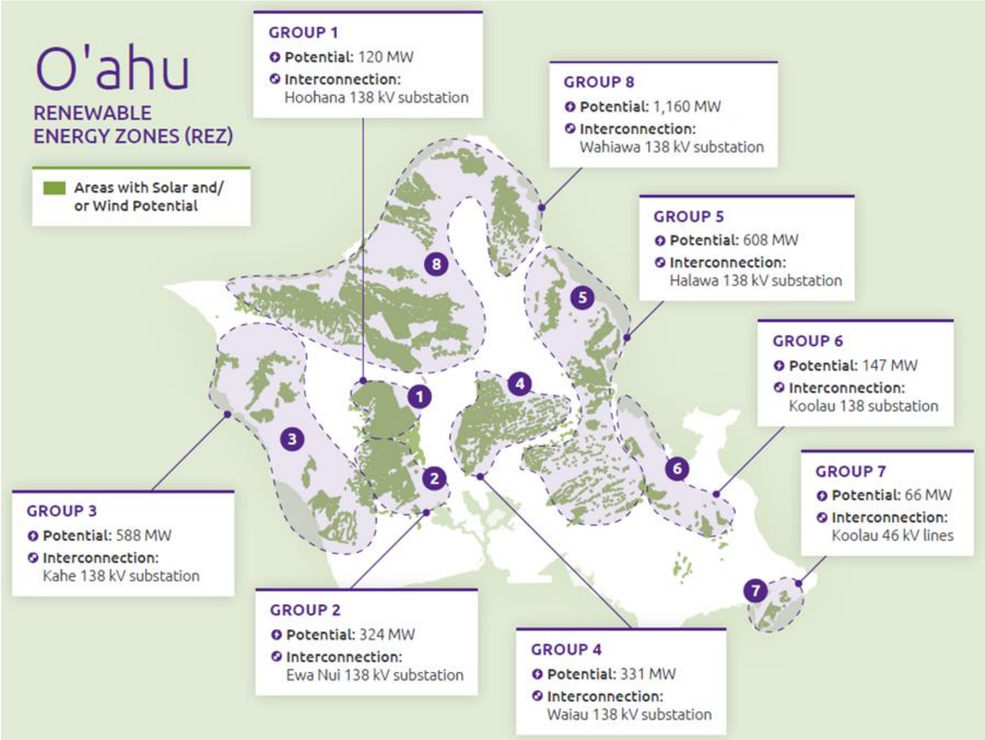
The developable potential for variable renewables was based on the resource potential study conducted by the National Renewable Energy Laboratory (NREL). Based on stakeholder feedback, NREL revised their study to include additional scenarios described in their July 30, 2021 *Assessment of Wind and Photovoltaic Technical Potential for the Hawaiian Electric Company*.

Consistent with the approved *March 2022 Inputs and Assumptions*, the “Alt-1” scenario developed in NREL’s revised study was adopted to define the additional variable renewable capacity that could be selected in the RESOLVE model. A summary of the resource potential study was described in Hawaiian Electric’s *March 2022 Inputs and Assumptions*. In this GNA, however, the solar and wind resource potential were not split by potential up to 15% sloped land and 30% sloped land. All potential capacity up to 30% sloped land was grouped by renewable energy zone, as described in the following section.

4.8 Renewable Energy Zone Enablement

Renewable energy zone (REZ) upgrades are composed of two costs: Transmission network expansion costs which are the transmission upgrades not associated with a particular REZ group but are required to support the flow of energy within the transmission system and REZ enablements which are the costs of new or upgraded transmission lines and new or expanded substations required to connect the transmission hub of each REZ group to the nearest transmission substation. The REZ enablement costs were included as part of the forecasted cost for new variable renewable resources to be selected by RESOLVE; however, no transmission network expansion costs were included. For further details on the REZ and associated enablement infrastructure, requirements and costs, see the Hawaiian Electric Transmission REZ Study as part of Hawaiian Electric’s *November 2021 GNA Methodology Report*.

Figure 7. Transmission REZ groups with MW potential on O‘ahu



The groups identified in the REZ study were aggregated by similar REZ enablement cost for modeling in RESOLVE to model a reasonable number of candidate resource options.

- Group 1 in RESOLVE (510 MW) – Groups 1, 2 and 7 from the REZ study
- Group 2 in RESOLVE (1,674 MW) – Groups 3, 4, 5 and 6 from the REZ study

- Group 3 in RESOLVE (1,160 MW) – Group 8 from the REZ study

4.9 Planned Resources

The model assumes 2027 as the first-year resources can be placed into service. The resources assumed to be in-service prior to 2027 are shown in Figure 8.

Figure 8: Future resources assumed to be in service prior to the start of the planning horizon

Resource	PV (MW)	BESS (MW/MWh)
CBRE Phase 2 Small	30	0 / 0
CBRE Phase 2 RFP	150	0 / 0
Hoohana Solar 1	52	52 / 218
Mililani Solar 1	39	39 / 156
Waiawa Solar	36	36 / 144
AES West O'ahu Solar	12.5	12.5 / 50
Barbers Point Solar	15	15 / 60
Kupono Solar	42	42 / 168
Kupehau*	60	60/240
Mahi Solar*	120	120 / 480
Mountain View Solar	7	7 / 35
Waiawa Phase 2 Solar	30	30 / 240
Kapolei Energy Storage	N/A	185 / 565

*Note the Mahi and Kupehau Solar projects power purchase agreements with Hawaiian Electric have since been declared null and void. In the Land Constrained cases, it was assumed these two projects are operational by 2030 as part of the constrained resource potential. Later in this report, sensitivities around the Mahi and Kupehau Solar project are discussed.

4.10 Near-Term Conditional Fossil-Fuel Generation Removal from Service

Hawaiian Electric assumed that certain amounts of firm fossil-fuel generating capacity would not be available for dispatch for the purposes of identifying grid needs. Removing firm fossil-fuel generating capacity planning assumptions noted below does not imply that the Company will retire the amount of firm generation capacity in the years indicated. The actual removal of generation from service is conditioned upon several factors, including whether sufficient resources have been acquired and placed in service to provide replacement grid services, reliability and resilience considerations, among others.

- Remove 90 MW fossil-fuel generation in 2024
- Remove 110 MW fossil-fuel generation in 2027
- Remove 170 MW fossil-fuel generation in 2029
- Remove 170 MW fossil-fuel generation in 2033

Sensitivities were also modeled to evaluate a scenario where the amended and restated power purchase agreement (PPA) for the 208 MW Kalaeloa Partners (KPLP) combined-cycle facility is approved for a 10-15-year term. Following that term, KPLP's PPA is assumed to not be renewed and the services provided by KPLP would need to be replaced through repowering of KPLP or other resources.

5 SCENARIO ANALYSIS

Several scenarios were examined to identify a range of potential grid needs to develop the Stage 3 RFP targets. Other scenarios laid out in the March 2022 Inputs & Assumptions will be considered further in the IGP process.

- Base Scenario – Assumes the base set of IGP sales and fuel price forecasts, in-service of the Stage 1 and 2 RFPs, CBRE RFP and GSPA projects. Existing power purchase agreements are assumed to terminate at the end of their current contract term. New variable renewable resources are allowed to be built up to the NREL Alt-1 resource potential. Certain existing fossil-fuel generating units are assumed to no longer be dispatched as described in Section 4.10. This scenario represents a net load forecast incorporating the most likely scenario of customer technology adoption.
    - Existing power purchase agreements include AES Coal, Kalaeloa Renewable Energy Park, Kalaeloa Solar Power II, Kapolei Sustainable Energy Park, Kawailoa Solar, Lanikuhana Solar, Waianae Solar, Waiawa PV, West Loch Solar, Kahuku Wind Farm, Kawailoa Wind Farm, Na Pua Makani Wind Farm.
- Low Load Scenario – Assumes the set of IGP sales forecasts that reduce customer demand including the high distributed energy resource (DER), high energy efficiency (EE) and low electric vehicle (EV) forecasts. Together, these forecast layers provide a low load to bookend or bound future, plausible demand that Hawaiian Electric should plan to serve. Other planning assumptions follow the Base scenario.
- High Load Scenario – Assumes the set of IGP sales forecasts that increase customer demand including the low DER, low EE and high EV forecasts. Together, these forecast layers provide a high load to bookend or bound future, plausible demand that the Company should plan to serve. Other planning assumptions follow the Base Scenario.
- Land Constrained Scenario – There is a limited amount of available land on Oʻahu, and a significant percentage of that land is on the side of mountains or near communities. Reduced resource capacities in this scenario are based on stakeholder feedback and represent what the Company believes can be added before needing additional infrastructure for REZs that will require an extensive community engagement process. Using the Base case, future grid-scale solar was assumed to have a reduced resource potential capacity of 270 MW and offshore wind was assumed to have a potential capacity of 400 MW. Biomass and land-based wind are assumed to be unavailable due to land constraints to build new wind projects and harvest biomass supply from purpose-grown crops. Similar to the High Load and Low Load bookends, the Base and Land Constrained scenarios provide reference points for future developable resource potential.

Figure 9 provides the Base, Land Constrained, High Load and Low Load scenarios forecast assumptions for EE, DER, EV and time-of-use (TOU) load shapes associated with customers who do not have DER or EV.

Figure 9. Forecast assumptions for the Base, High Load and Low Load scenarios

Forecast Layer	Base & Land Constrained	High Load	Low Load
EE	Base	Low	High
DER	Base	Low	High
EV	Base	High	Low
EV Charging Shape	Managed	Unmanaged	Managed
Non-DER, Non-EV TOU	Base	Low	High

While the load forecast assumption for the Land Constrained scenario is the same as the Base scenario, the Land Constrained scenario is more limited in what resources can be built. Figure 10 shows the differences in renewable resource potential between the Land Constrained scenario and all other scenarios. It is important to note that in the Base scenario, of the 3,300 MW of solar power that can be developed, approximately 2,300 MW is expected to be on land with slopes greater than 15% but less than 30% and approximately 1,000 MW on land with slopes less than or equal to 15%.

Figure 10. Differences in renewable resource potential between the Land Constrained scenario and the Base, High Load and Low Load scenarios

Resource (MW)	Base High Load Low Load	Land Constrained
Solar	3,300	270
Land-Based Wind	164	0
Offshore Wind	600	400
Biomass	No Limit	0
Biofuel	No Limit	No Limit

6 RESOURCE GRID NEEDS ANALYSIS

The RESOLVE capacity expansion model was used to develop an optimized resource plan using the assumptions described for the Base, Land Constrained, Low Load and High Load scenarios. The results of the RESOLVE modeling were used to inform the variable renewable and storage additions assumed in subsequent analyses. Renewable firm resource additions were further analyzed through the resource adequacy analysis.

To verify that the reliability capacity needs were met using 30% Energy Reserve Margin (ERM) criteria for Oʻahu, a detailed ERM analysis was performed in PLEXOS using the 1-sigma HDC for wind and solar resources, including rooftop solar, which is a customer resource modeled on the supply-side. Since this analysis was started at the end of 2021, the use of 30% ERM and 1-sigma HDC for wind and solar resources is not consistent with the Decision and Order No. 38482 on June 30, 2022. The resource plans for the Base and Land Constrained scenarios were further examined to determine whether the planned and selected resources met the ERM criteria as bookends on the available variable renewable resources that could be developed. Because the paired variable renewables and storage contribute toward capacity, high and low levels of these resources were considered to examine the operations of the existing generating units and future renewable firm generating units. For example, in 2030, the Base scenario adds 1,740 MW of variable renewables (solar, wind, battery energy storage) while the Land Constrained scenario adds a much lower 270 MW of variable renewables (solar, battery energy storage).

Based on the results of the ERM analysis, several firm generation capacity targets were identified. A range of new firm renewable generators including combustion turbines, combined cycles, internal combustion engines and biomass were added to the Base and Land Constrained scenarios as proxies for the types of proposals that may bid into the solution sourcing process to confirm that most of the capacity need was met. A procurement scenario was then developed based on the capacity expansion and ERM resource adequacy analysis.

Due to on-going discussions regarding ERM and HDC, and expressed commission concerns, significant time was dedicated to assessing resource adequacy using the probabilistic methodology endorsed by the TAP. In consultation with the TAP and STWG, a significant number of sensitivities were run to thoroughly assess resource adequacy in 2029-2030 through reliability metrics such as loss of load expectation, loss of load events, loss of load hours and expected unserved energy.

More on Resource Adequacy

Recently, within the utility industry and locally, there has been a heightened awareness of grid reliability. Figure 11 shows the different components and considerations in ensuring grid reliability.

Figure 11. Grid reliability components and considerations

System Stability	System Balancing	Transmission and Distribution	Resource Adequacy	Resilience
▪ High penetrations of inverter based resources ▪ Essential reliability services ▪ Frequency, voltage, stability	▪ Wind and solar variability and uncertainty ▪ Managing and balancing of resources	▪ Equipment failures, vegetation, auto accidents ▪ Grid modernization – automation and field devices to reduce duration of outages ▪ Outages commonly measured in frequency and duration	▪ Seasonal demand/load uncertainty ▪ Generator/BESS failures or outages ▪ Multiple days in a row of low solar wind output ▪ 1 day in 4.5 years annual loss of load probability	▪ Hurricanes, storms, flooding, lava flow, and other extreme weather events ▪ Cybersecurity ▪ Hardened infrastructure ▪ Microgrid solutions

While each type of reliability is important to delivering consistent, reliable electricity, the primary focus of this report is on generation reliability and resource adequacy. As new variable resources are integrated onto the grid and with the desire to retire fossil-fueled generation as soon as practicable, ensuring resource adequacy will be critical to combating climate change and realizing a decarbonized economy. The grid needs analysis takes an in-depth look at this issue.

Resource Adequacy must first be understood and defined. A recent report published in February 2022 by Energy + Environmental Economics, *Resource Adequacy in the Desert Southwest*, defines resource adequacy in the following way:

> Resource adequacy is the ability of an electric power system to produce sufficient generation to meet loads across a broad range of weather and system operating conditions, subject to a long-run reliability standard that limits the frequency of shortfalls to very rare instances. The resource adequacy of a system thus depends on the characteristics of its load—seasonal patterns, weather sensitivity, hourly patterns—as well as its resources—size, dispatchability, outage rates and other limitations on availability. Ensuring resource adequacy is an important goal for utilities seeking to provide reliable service to their customers.

The grid needs analysis provided in this report considers these factors by examining generation reliability in two distinct ways, an energy reserve margin analysis and a probabilistic resource adequacy analysis. Resource adequacy in Hawai'i is unique because of the extremely high penetration of rooftop solar and grid-scale solar and storage projects. In addition, Hawai'i is not interconnected to any other grid where power can be imported from neighboring states if there are shortfalls in energy supply. Hawai'i needs to be energy self-sufficient.

NERC Definition of Adequacy

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.

Resilience has also come into sharper focus with recent events on the US mainland and here in Hawaiʻi. While resource adequacy plans for reasonably anticipated events, as discussed later in this report, Hawaiian Electric considered resilience and extreme events in developing the procurement scenario. Further study is needed in this area as resilience is intertwined with other aspects of the grid such as the transmission and distribution system.

6.1 Customer Technology Adoption is a Priority

As described in this section, Hawaiian Electric took a customer first approach to the planning process. Customer technologies are first forecasted based on Hawaiʻi's robust distributed resource market. Their flexibility is maximized to meet grid needs and deliver services. The remaining load to be served is then optimized around grid-scale resources that can meet system needs through the capacity expansion modeling.

6.1.1 Customer Technologies as a Resource to Fulfill Grid Needs

In planning for future grid needs, Hawaiian Electric assumes a forecasted uptake of customer technologies for energy efficiency, distributed energy resources, and electric vehicles. The base set of forecasts for these customer technologies form the best guess of their future adoption and influence the resulting grid needs that are solved for in the subsequent modeling conducted in RESOLVE and PLEXOS. Summarized below are the incremental additions of energy efficiency, solar, and electric vehicles assumed in the Base forecast by 2030.

To reduce carbon by 70% by 2030, in the near-term, in the base scenario the solution sourcing process must seek to acquire customer resources as shown in Figure 12, otherwise carbon reductions may not be realized and put additional strain on the system resources to meet forecasted demand for electricity:

Figure 12. Assumed customer resources needed to achieve 2030 goals

Customer Technology (incremental from 2021 levels)	Peak Load Impact (MW)	Impact to Sales (GWh)	Approximate Quantity
Energy Efficiency	145	1,014	N/A
Electric Vehicles	29	183	43,536 EVs
Private Rooftop Solar	253 (Installed Capacity)	437	26,292 systems
Private Battery Energy Storage	149 MW / 394 MWh (Installed Capacity)	-14	26,261 systems
Non-DER/EV Time-of-Use	4	N/A	N/A

6.1.1.1 Energy Efficiency

A significant portion of load, both capacity and energy, is anticipated to be served through future energy efficiency. While future work in the IGP will include energy efficiency supply curves to determine whether it's optimal to acquire more than the forecast energy efficiency, the base forecast provides a reasonable level of uptake to assume for identifying grid needs. As noted in the March 2022 inputs and assumptions, the energy efficiency forecast is based on projections from the July 2020 State of Hawaii Market Potential Study prepared by the Applied Energy Group (AEG) and sponsored by the Hawaiʻi Public Utilities Commission. The base forecast is composed of the Business as Usual potential forecast and Codes and Standards forecasts from the potential study. The Business as Usual forecast represents savings from realistic customer adoption of energy efficiency measures through future interventions that were similar in nature to existing interventions. The Codes and Standards forecast represents savings from building codes and appliance standards.

6.1.1.2 Electric Vehicles

The impact of the electrification of transportation on load was forecasted through the adoption of light duty electric vehicles and electric buses. The light duty electric vehicle forecast was based on an adoption model developed by Integral Analytics as described in the EoT Roadmap. The latest unmanaged charging profiles for residential and commercial light duty electric vehicles were updated by leveraging data from the Hawaiian Electric's DC fast charging network and a case study conducted through the deployment of EnelX's Level 2 chargers in Hawaiʻi. Electric buses were forecast based on information provided by the Hawaiian Electric's Electrification of Transportation team following discussions with several bus operators throughout Honolulu, Hawaiʻi, and Maui counties.

6.1.1.3 Private Rooftop Solar

Future DER capacity was forecast using two time horizons: near term, over the next three years to reflect the current pace of incoming applications and executed agreements for existing programs and longer term using a model-based approach. The longer term, economic choice model considered the installed cost of PV and BESS systems, incentives, electricity prices, future program structure, and addressable market of customers that have the potential to install DER, among other assumptions.

The future new tariff assumed export compensation and allowed for controllability, based on the standard DER tariff that is proposed in the DER docket. On Oʻahu and Maui, the forecast also incorporated the Emergency Demand Response Program, Scheduled Dispatch Program or Battery Bonus and assumed that an upfront incentive of $250/kW would continue beyond Battery Bonus for new DER customers to provide grid services similar to a bring your own device type program.

While the forecasted uptake of DER through Battery Bonus was assumed to export the battery system's rated capacity, if energy was available, for a two-hour duration between 5 PM – 9 PM, DER was modeled as a resource in the RESOLVE and PLEXOS models and split into two classes, uncontrollable legacy DER and controllable future DER that can provide grid services. Modeling DER as a resource is particularly important for assessing resource adequacy as it allows the DER to flexibly serve demand and provide capacity in high need hours while also reflecting changing availability of the PV production for the various weather years modeled.

6.1.1.4 Program Design to Ensure Cost Effective Customer Adoption of DER, EV, and EE

Hawaiian Electric proposed a suite of "freeze" cases to examine the value of forecasted DER, EV, and EE assumed in the load forecast. This modeling will be used in the program design phase of IGP as part of the solution sourcing, to follow the grid needs assessment phase. As the grid needs assessment assumes the forecasted uptake of DER, EV, and EE, the impact of these customer technologies on grid needs is already accounted for. During solution sourcing, the value of the forecasted uptake of DER, EV, and EE will be assessed using the "freeze" cases to determine the compensation and incentives that can be offered cost effectively in the design of new programs and achieve the forecasted levels of DER, EV, and EE that were initially assumed as part of a balanced resource portfolio.

Notwithstanding the above, with DER and EE frozen using the freeze forecasts provided in the IGP inputs and assumptions, additional firm capacity was required to achieve a similar level of reliability as the case with their forecasted uptake by year 2029. This analysis informs the capacity value that these customer-adopted resources provide to the system to fulfill grid needs and is discussed in more detail in Section 6.5.7.

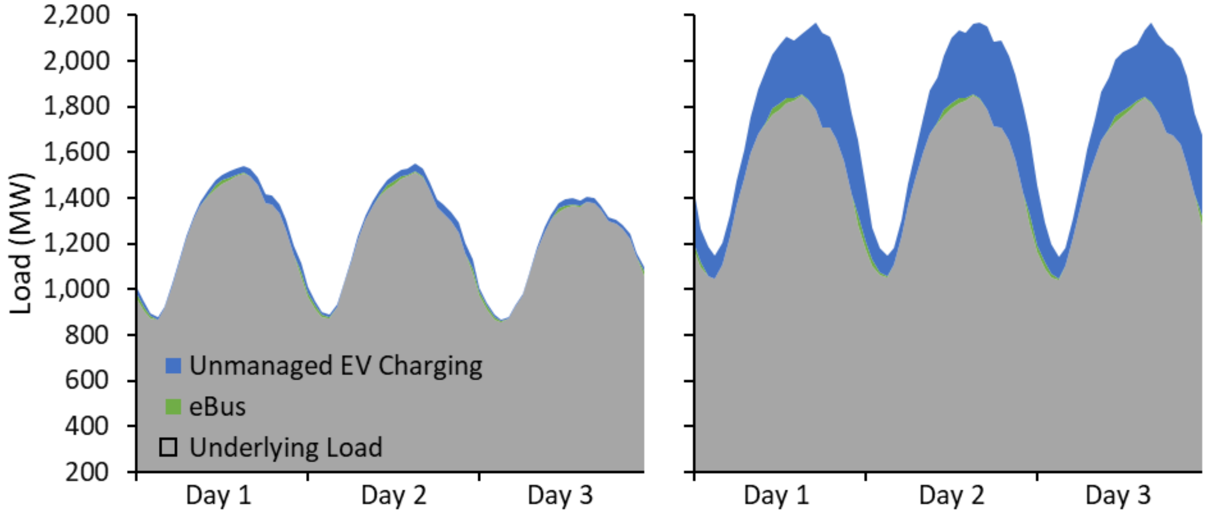
6.1.2 Flexible Customer Resources

Customer resources that include private rooftop solar, distributed battery energy storage, electric vehicles and energy efficiency are necessary to achieve Hawaiian Electric's and the state's decarbonization goals. Customers will seek energy self-sufficiency and resilience by adopting these technologies. Many of these customer resources are flexible and can interact with the grid in a manner that increases the efficiency of grid operations, including contributing to a reliable energy system. Many of Hawaiian Electric's current and planned programs enable this interaction. However, as the distributed energy resource market continues to evolve and customer technologies advance, new innovative programs and customer engagement will be needed. The following sections take a closer look at the future of customer resources in contributing to reliability needs and more efficient grid operations.

6.1.2.1 Managing Flexible Loads

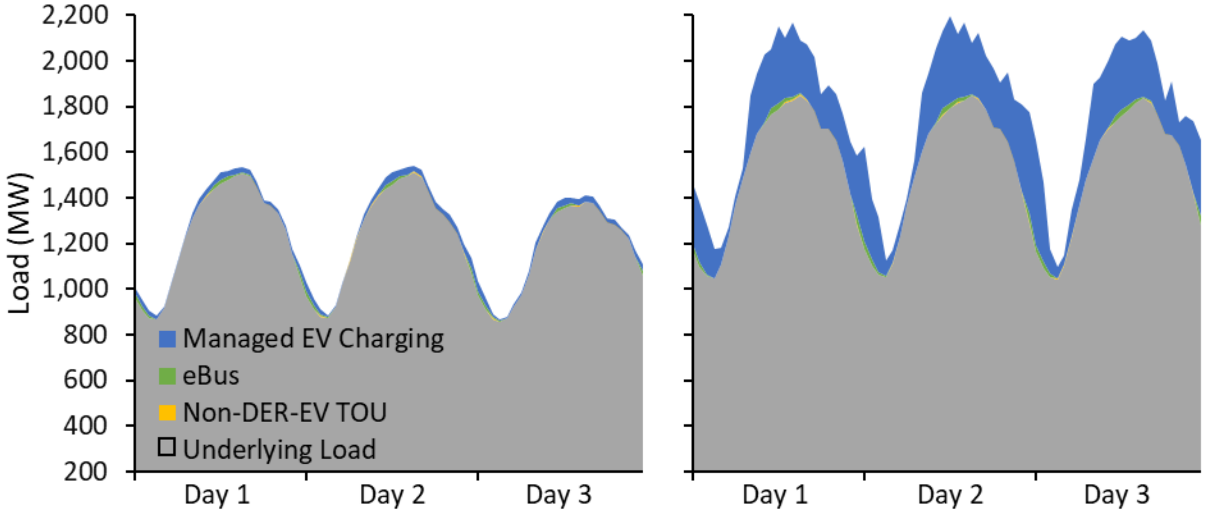
Electric vehicles and electric buses are examples of distributed resources that can increase electricity demand and require more generation resources. In 2030, forecasted electric vehicle charging is a modest incremental load to the system primarily due to the long stock rollover durations for light-duty vehicles. However, as shown in Figure 13, in year 2050, significant load increases are observed due to more electric vehicles on the road in 2050.

Figure 13. Illustrative days showing the impact of unmanaged EV charging. At left, Year 2030; At right, Year 2050



The loads in 2050 are significant, but as shown in Figure 14, managing charging levels can shift some of the unmanaged charging during the evening peak to the daytime when abundant clean solar electricity is available to charge electric vehicles. Electric vehicle charging is considered flexible in that it can be managed to increase system load when the electricity is cheaper and in lower demand.

Figure 14. Illustrative days showing the impact of managed EV charging. At left, Year 2030; At right, Year 2050

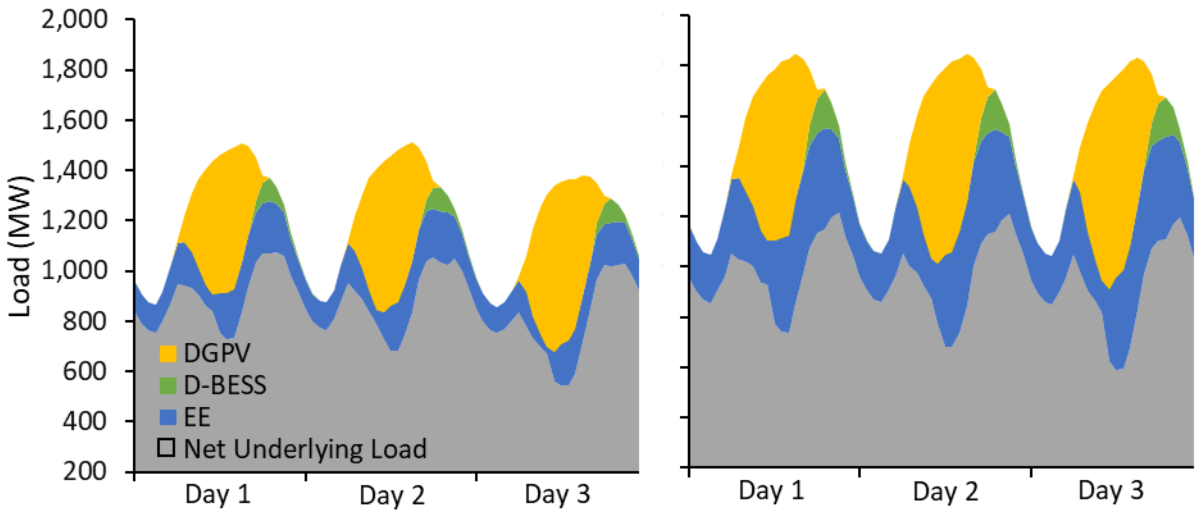


Mandatory time-of-use or TOU rates are envisioned for residential customers who typically use most of their electricity in the evening when returning home from work to cook dinner, take a hot shower, or run their washer and dryer. Hawaiian Electric notes that residential usage has been elevated during the COVID pandemic as it appears that most residents are spending more time at home than pre-pandemic. The forecasted TOU response from customer load changes for customers who do not own DER (rooftop solar) or electric vehicles is quite small. It is expected that the customers with flexible resources like distributed battery energy storage and electric vehicles will be most willing to change habits and shift their energy loads to a low-demand period.

Energy efficiencies, rooftop solar (DGPV) and distributed battery energy storage (D-BESS) are examples of distributed resources that can decrease load or offset load. Energy efficiency measures are permanent in nature in that the load is not necessarily shifting but reduced through more efficient equipment or appliances like air conditioners, heat pump water heaters, LED light bulbs, commercial chillers, among others. The impact of these resources that can reduce or offset loads are seen in Figure 15.

DGPV and D-BESS are normally coupled together and privately owned by customers who may buy or lease such systems to offset their own home load and export any excess. These distributed resources have unique potential. Even though they do not permanently remove load from the system, they are flexible technologies that have the effect of making loads appear flexible. Additionally, in the grid needs assessment, future DGPV is assumed to be controllable on the supply-side of the grid providing flexibility to align DGPV exports with system needs. Aggregated DGPV is also made available to the model as a dispatchable resource providing similar services as grid-scale solar projects. Through customer programs, customers may receive compensation for providing various services to the grid in alignment with system needs. For example, as shown in Figure 15, below, DGPV in aggregate can reduce load during the daytime and when coupled with a battery energy storage system, further reduce loads after the sun goes down, as shown in the green shaded area. Likewise, energy efficiency can significantly reduce loads during all times of the day, putting less strain on the generation system to meet the demand that Hawaiian Electric would otherwise serve.

Figure 15. Illustrative days showing the impact of DGPV, D-BESS and EE. At left, Year 2030; At right, Year 2050



When considering all the various customer technologies together, the remaining load is called the net load which then must be served by grid-scale resources that are provided by Hawaiian Electric or independent power producers. The net load with managed and unmanaged charging is shown in Figure 16 below in the green and gold lines. Managed charging is achieved through price signals such as time varying rates, and other programs such as workplace EV charging. Unmanaged charging is an estimate of when customers would charge their EVs without any price signals or incentives to encourage charging at certain times. As discussed above, because of lower electric vehicle adoption in 2030, there is a small difference in the evening peak between the managed and unmanaged charging. However, in year 2050 with significant load additions from electric vehicle charging, during what is typically the most expensive hours for energy in the evening, there is a significant difference in the net load between the managed and unmanaged electric vehicle charging case. This represents the importance of customers choosing to charge during the day when more generation capacity is available and generally cheaper than during the evening hours.

Figure 16. Daily load flexibility. At left, Year 2030; At right, Year 2050

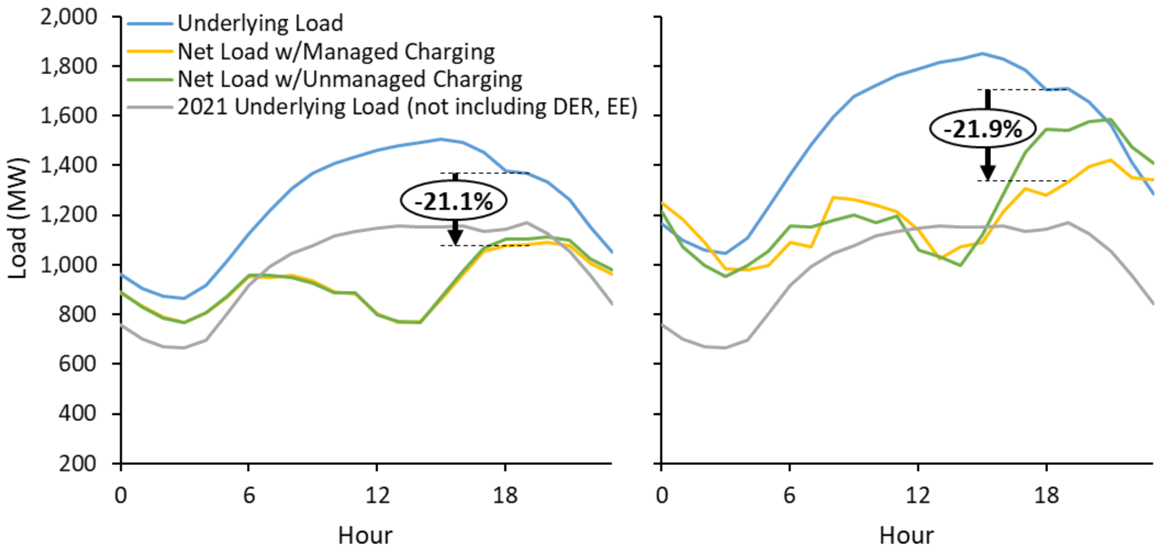
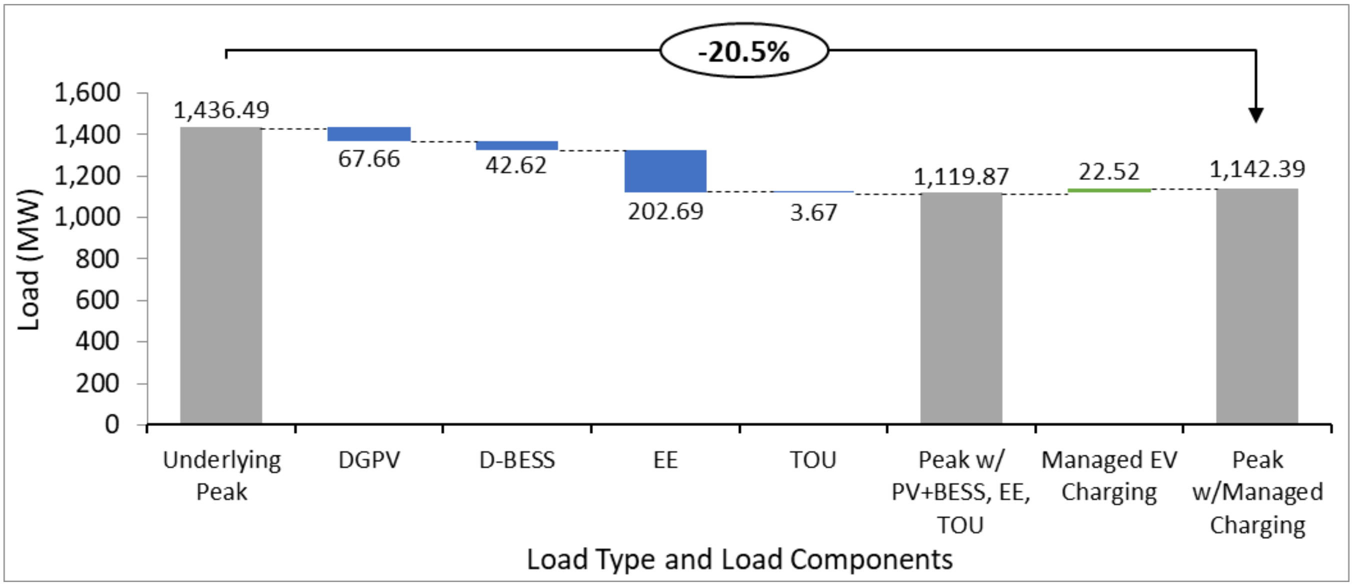


Figure 16 also shows in blue the underlying loads without accounting for customer technologies. This is the load Hawaiian Electric would need to serve if customers did not adopt any efficiencies measures, electric vehicles, DGPV or D-BESS. It means significantly more generating resources would need to be acquired by Hawaiian Electric to ensure sufficient generating resources to meet the demand. Additionally, between the underlying load in blue and the managed charging (due to time varying rates and programs) net load in gold, the load is reduced as much as 22% during the evening hours.

Figure 17 below, shows that in the peak hour in year 2030 the forecasted DGPV, D-BESS, EE and TOU can offset the peak impacts of EV charging, and in total reduce the peak load hour by approximately 20.5%. As electric vehicle charging increases in later years peak reductions are less but still significant.

Figure 17. Reductions in year 2030 peak hour load due to customer resources



6.2 Procurement Scenario for Remaining Grid Needs

This section summarizes the procurement scenario that was optimized and validated by a probabilistic resource adequacy analysis. The procurement scenario was developed using RESOLVE and PLEXOS to optimize and validate resource adequacy and operations of the grid which is further described following this section and in the appendix to this report.

The grid needs analysis that included capacity expansion plans, resource adequacy analysis and an iteration to validate the capacity and energy needs with proxy firm generating resources indicates that the near-term needs of the system that Hawaiian Electric should acquire as part of the Stage 3 procurement are:

- 544 GWhs of renewable dispatchable generation in 2027 to offset energy previously provided by the AES coal plant and provide a market test of the remaining, developable renewable potential that can be put into service by 2027. The target renewable energy can be further adjusted depending on the final outcome of Stage 1 and 2 projects.
- 300-500 MW of renewable firm generation in 2029 or as soon as practicable to facilitate removal from service of older fossil fuel generating units and 200 MW in 2033.
  - Probabilistic testing with a range of firm thermal and variable renewable additions showed that compliance with the three reliability standards (LOLE, LOLH, EUE) can be achieved with 200 – 400 MW of new firm thermal generation. (Section 6.5)
  - ERM testing identified an average need of 536 MW, 165 hours when the removal of KPLP and Mahi was assumed. (Section 6.4.1)
  - The ERM need was validated when 508 – 688 MW of firm generation was added. While residual shortfalls persisted after the firm generation additions, they decreased as the firm thermal capacity additions increased. (Section 6.4.2)

- The targets for variable and firm renewables are consistent with the RESOLVE optimizations and probabilistic testing. The length of time to develop firm generation warrants a more realistic in-service date of 2029.

While 726 GWhs of renewable variable dispatchable generation is selected in 2027 by RESOLVE (Section 6.3), the selected resource by the model is land-based wind. New land-based wind in the immediate-term would likely require additional infrastructure and face community opposition based on recent history of wind projects. While the Assessment of Wind and Photovoltaic Technical Potential determined that 163 MW of land-based wind capacity remains on Oʻahu, the resources are located on the north shore and west side of Oʻahu where development at both locations have been recently opposed by the community. Additionally, on the north shore, an additional transmission substation in Wahiawa would be required according to the REZ study. Therefore, it is recommended to target procurement of renewable energy, after accounting for Stage 1 and 2 projects, needed to offset coal-based energy previously provided by the AES Coal plant and maximize the current transmission infrastructure without triggering the need for new transmission facilities. This will ensure that oil consumption does not substantially increase following the retirement of the AES coal plant. The 544 GWh renewable energy target is approximately equal to the 270 MW land constrained grid-scale solar amount and 75% of the energy selected by the RESOLVE model in 2027. If attractive proposals are received the procurement should allow more than the 544 GWh target to be awarded in the Stage 3 procurement.

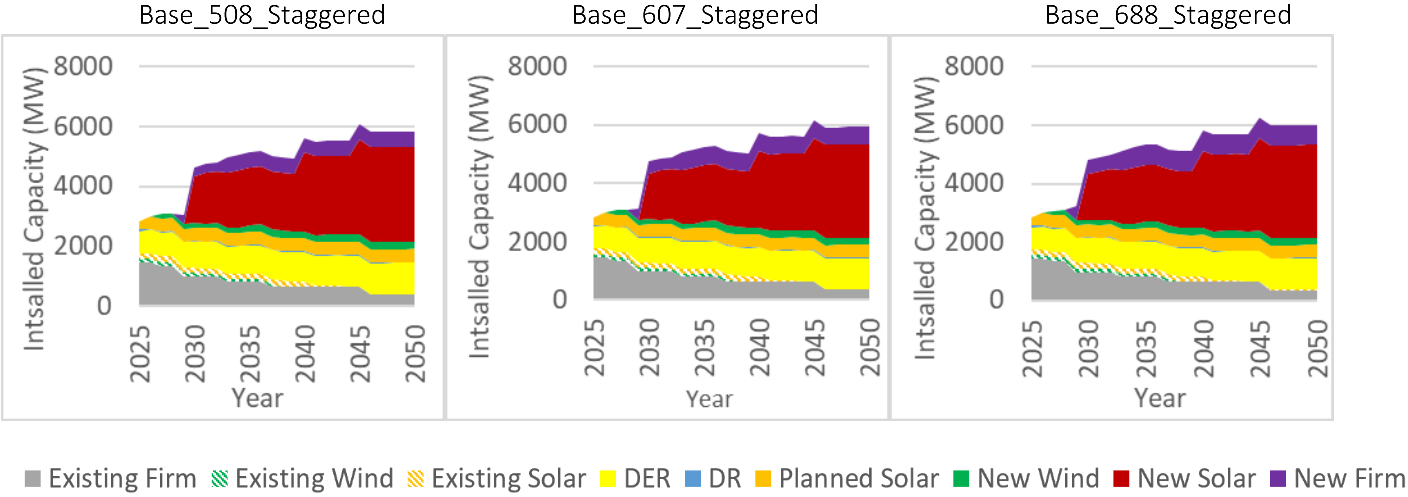
As noted earlier in this report, further work is required to engage communities to develop potential renewable energy zones to interconnect larger amounts of grid-scale renewable energy. This engagement is on-going and is expected to be a key part of the IGP process over the next year in preparation for the competitive procurements to follow the IGP grid needs assessments and following the Stage 3 procurement.

6.2.1 Staggered Installation of Firm Renewable Generation

Due to the possibility that 500-700 MW of renewable firm generation may not be able to be installed by 2029, and to reduce the operational and planning risk of having an entire block of firm generation removed from service in the same year when its contract term ends, the firm unit installations were staggered in different years. For each the 500 MW, 600 MW and 700 MW renewable firm generation scenarios, the total firm capacity is assumed to be installed in 2029, except for 200 MW, which was assumed to be installed in 2033. The 2033 date for 200 MW is approximately when an approved 10-year contract extension of KPLP would be set to expire. An ERM analysis was performed in PLEXOS assuming that approximately 300 MW, 400 MW and 500 MW were installed in 2029 and 200 MW installed in 2033.

Section 9.1 Capacity Expansion Plans provides the resource plan for these cases. Shown below in Figure 18 is the installed capacity trend for various resource categories for the Base_508_Staggered, Base_607_Staggered and Base_688_Staggered scenarios, respectively.

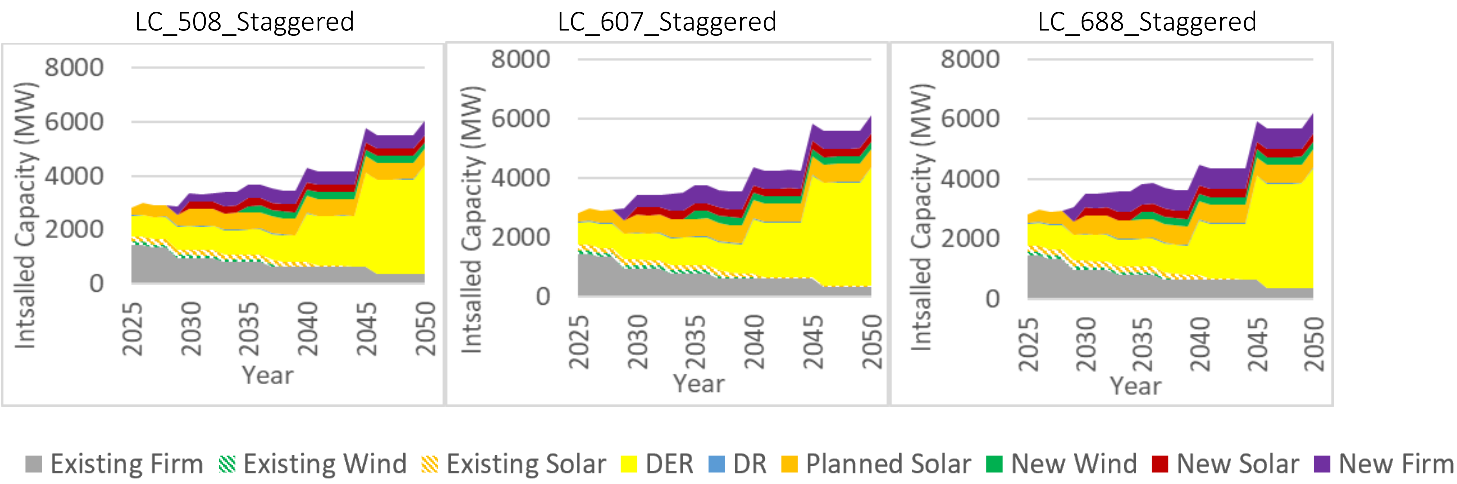
Figure 18. Installed capacity trends for resource categories by scenario. At left, Base_508_Staggered; at center, Base_607_Staggered; at right, Base_688_Staggered



As the existing fossil-fuel firm generation in gray declines over time with the removal of existing thermal generating units from service over the planning period, the replacement thermal capacity of new renewable firm in purple is still much less than the variable renewables considered in the portfolio.

The same firm renewable capacity was installed in the Land Constrained (LC) case. Shown below in Figure 19 is the installed capacity trend for various resource categories for the LC_508_Staggered, LC_607_Staggered and LC_688_Staggered scenarios, respectively. The Land Constrained case, which limits the development of future grid-scale renewables, relies upon distributed paired solar in later years of the planning horizon.

Figure 19. Installed capacity trends for resource categories by scenario. At left, LC_508_Staggered; at center, LC_607_Staggered; at right, LC_688_Staggered



6.2.2 Procurement Scenario ERM Analysis

Hawaiian Electric performed an ERM analysis on the staggering of new firm generation in PLEXOS. A summary of the number of instances of a given capacity shortfall in 2029 and 2033 is shown in Figure 20 and

Figure 21, respectively, for the three different Base scenarios and three different Land Constrained scenarios.

Figure 20. Histograms of capacity shortfall in 2029 grouped by scenario and shortfall magnitude

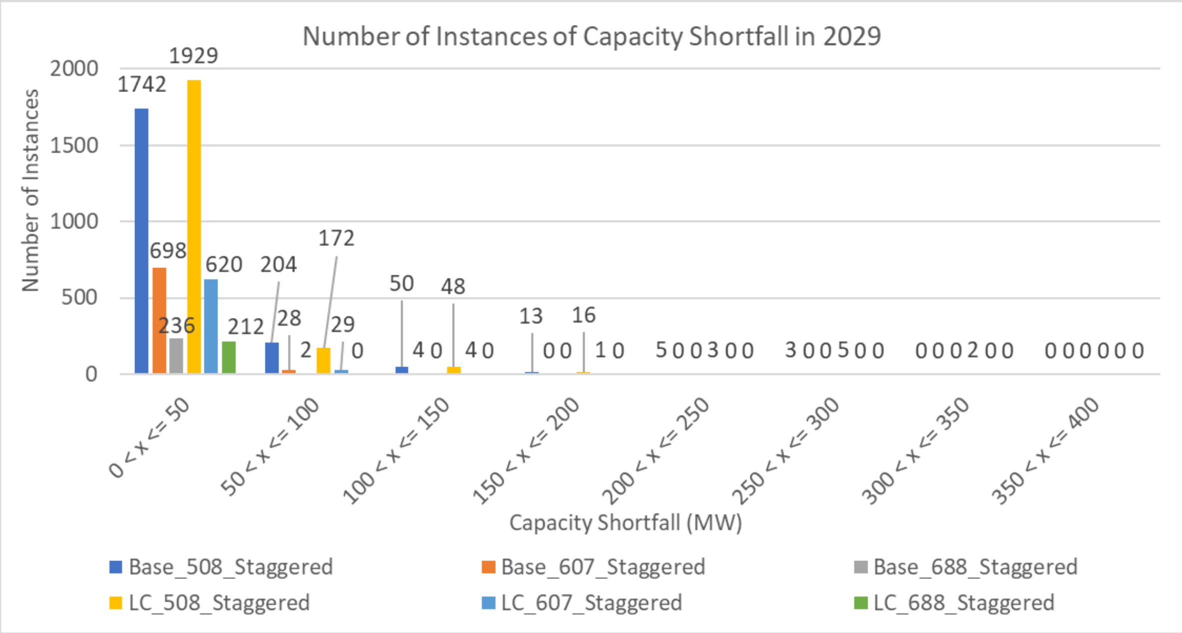
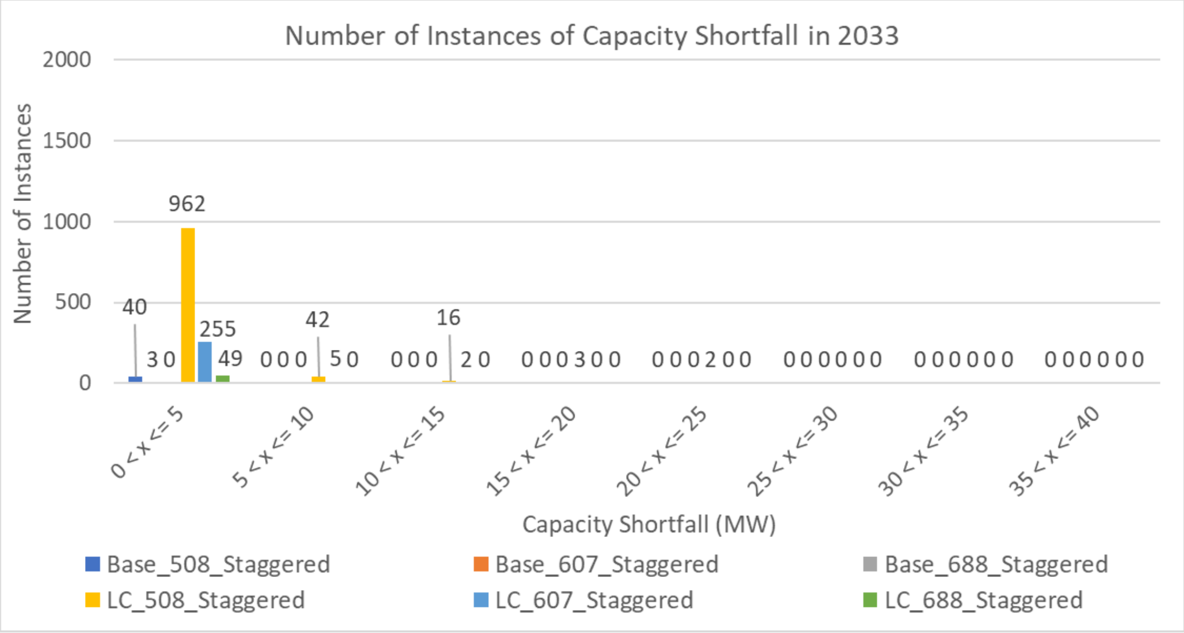


Figure 21. Histogram of capacity shortfall in 2033 grouped by scenario and shortfall magnitude



A summary of the number of instances of a given consecutive hours shortfall in 2029 and 2033 is shown in Figure 22 and Figure 23, respectively, for the three different Base scenarios and three different Land Constrained scenarios.

Figure 22. Histograms of capacity shortfall in 2029 grouped by scenario and shortfall duration

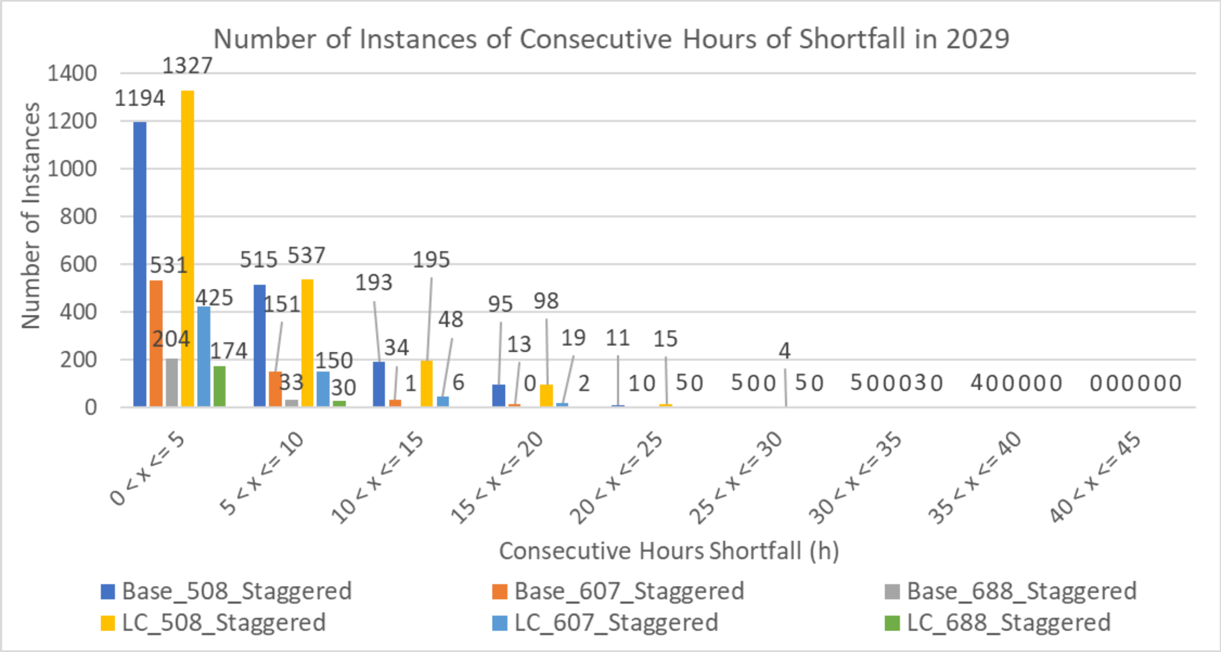
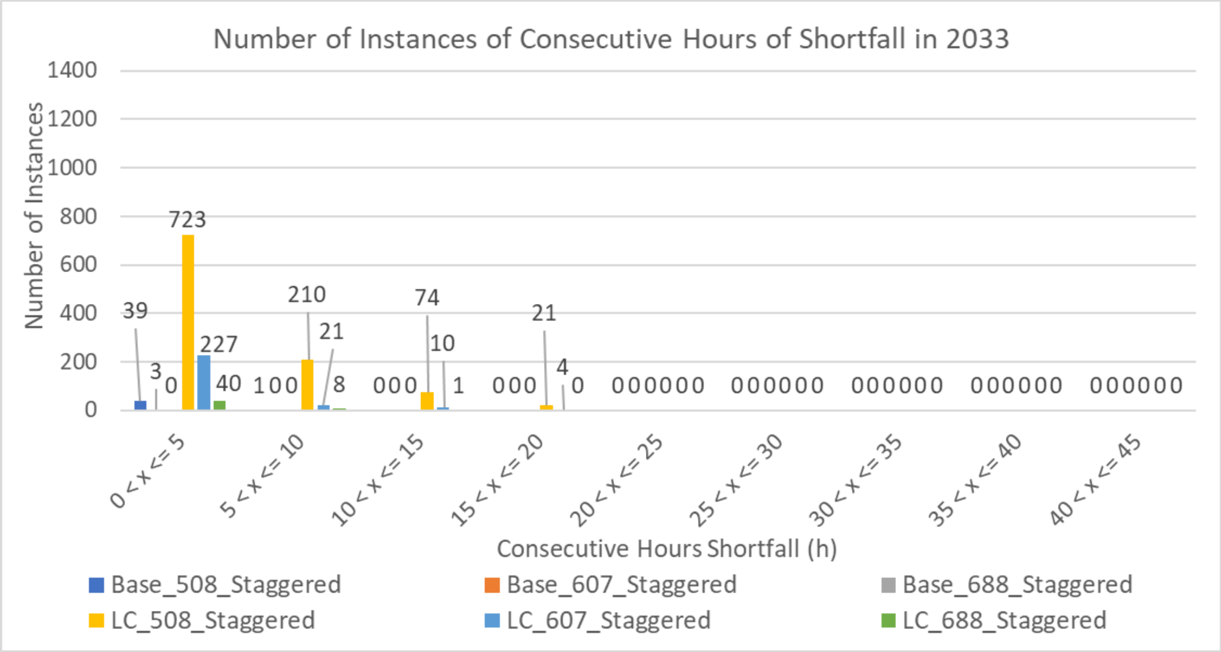


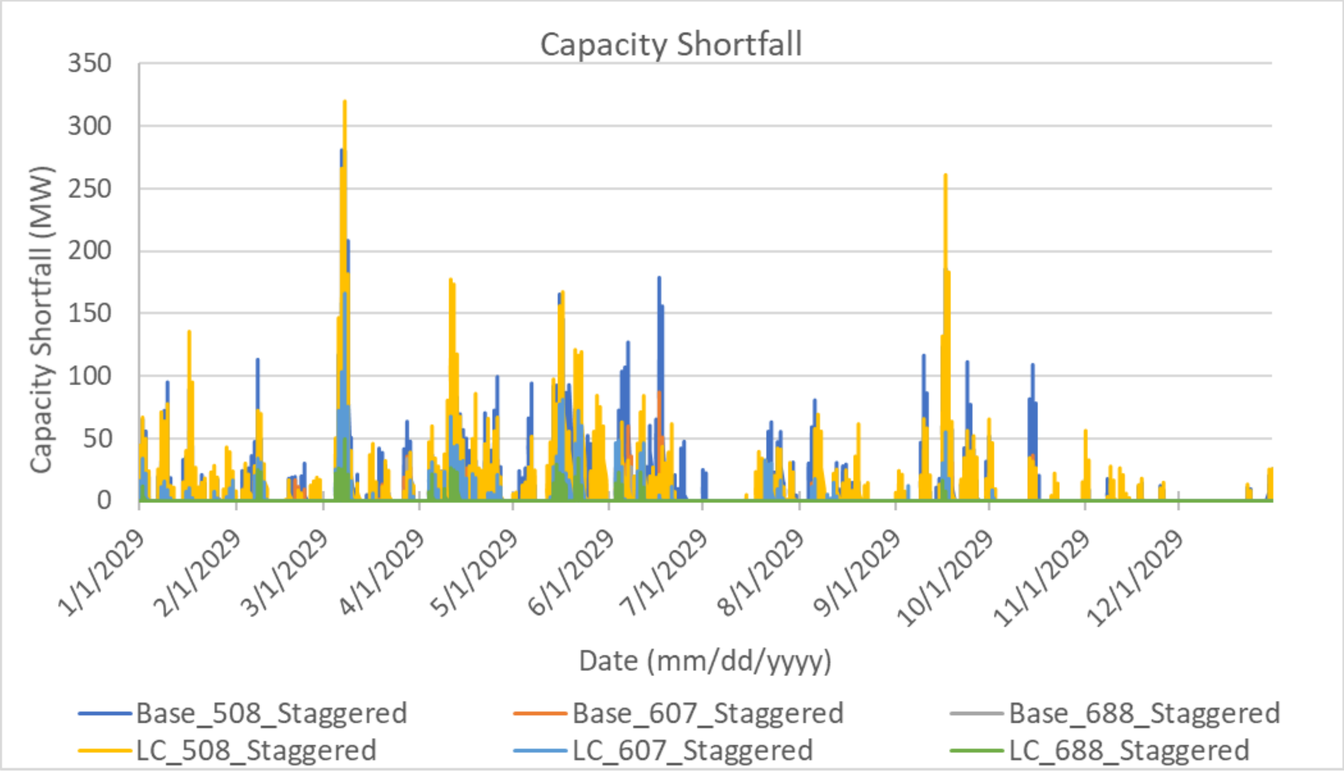
Figure 23. Histograms of capacity shortfall in 2033 grouped by scenario and shortfall duration



When the firm resource is added in 2029, the capacity shortfall and number of instances of shortfall decreases. Similarly, when the firm resource is added in 2029, the consecutive hours shortfall and number of instances of shortfall decreases. The Base scenario also has less shortfall, both in magnitude and frequency, than the Land Constrained case due to the higher amounts of renewables added.

Shown below in Figure 24 is a detailed look of the capacity shortfall for the three different Base scenarios and three different Land Constraint scenarios in 2029. As expected, as the size of the firm capacity increases, there is less capacity shortfall.

Figure 24. Year 2029 hourly capacity shortfall. Base and Land Constrained (staggered) scenarios



Shown below in Figure 25 and Figure 26 is the dispatch for a high-renewable day in 2029 and low-renewable day in 2029, respectively. Note that this is the dispatch in the ERM analysis, and therefore, variable renewable production is defined by the HDC and is not representative of the dispatch of the new firm units during normal operation.

Similar to the previous section, even on a day with high renewable energy and the large number of renewables added in 2030, the new firm generators are still needed to help meet the capacity and energy requirement. The need for firm generation to help meet the capacity and energy requirement is increased on the low-renewable days, as well as, when existing firm generation is removed from service in 2033.

Figure 25. Daily chart – ERM simulation – Base_508_Staggered scenario – High renewable day

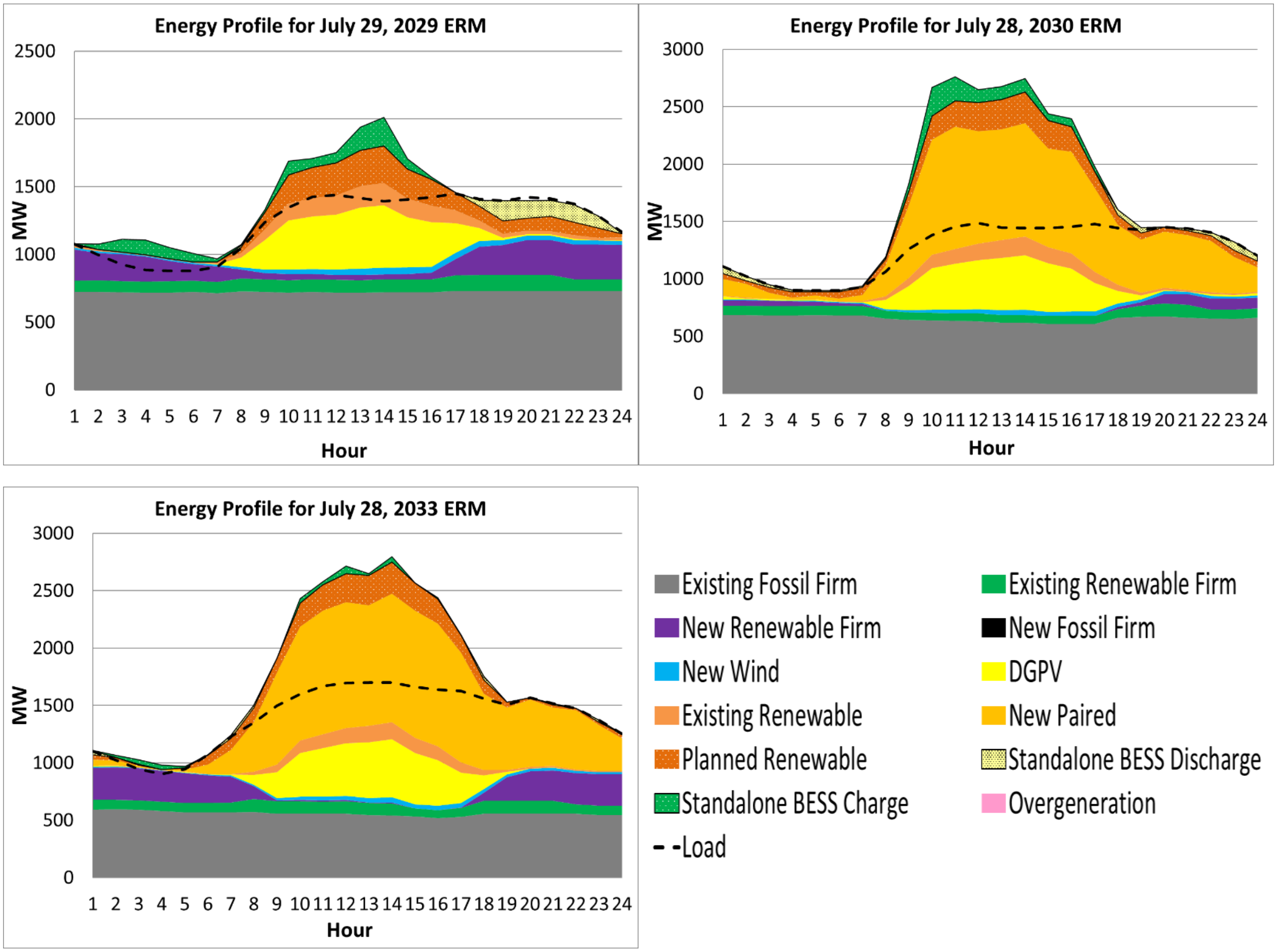
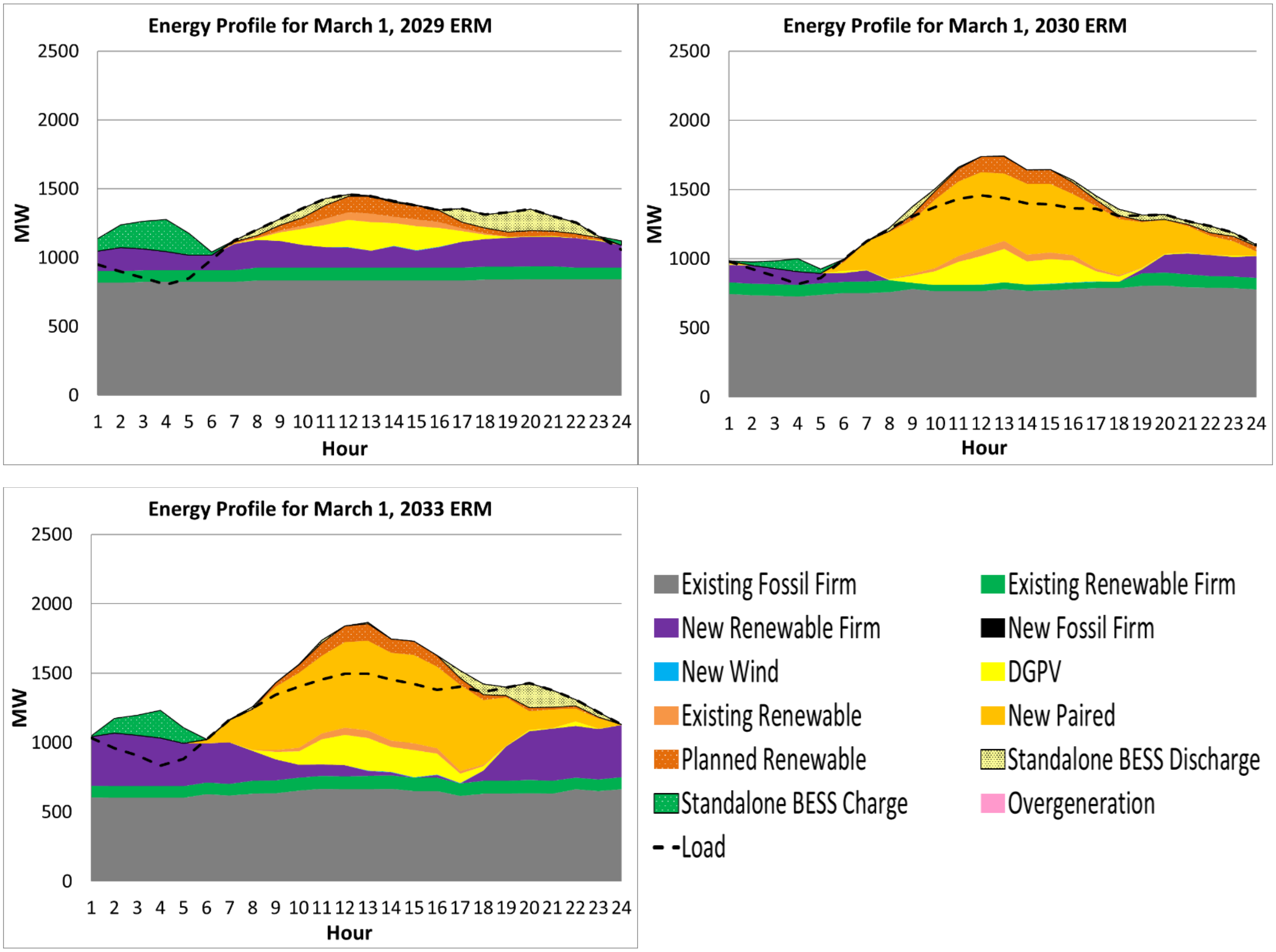


Figure 26. Daily chart – ERM simulation – Base_508_Staggered scenario – Low renewable day



6.2.3 Procurement Scenario Probabilistic Analysis

As detailed in Section 6.5, the reliability impact of adding resources varies by resource type and quantity. Several different resources were evaluated to address reliability concerns in year 2029 including firm generation, hybrid solar, land-based wind, offshore wind, long-duration energy storage, short-duration energy storage, and delayed deactivation of existing generators. The analyses also demonstrate that there are diminishing returns on the extended addition of one resource type and that there are portfolio benefits to adding a diverse mix of resources to address reliability concerns.

In Section 6.5.2, at lower additions of hybrid solar (paired PV + BESS), greater amounts of thermal generation may be needed to achieve reliability. Cases were run with 270 MW of hybrid solar and 400 MW of firm thermal generation, 958 MW of hybrid solar and 300 MW of firm thermal generation, and 1,600 MW of hybrid solar and 200 MW of firm thermal generation. Each of these cases resulted in reliable systems as measured by established reliability metrics for LOLE, LOLH and EUE used by other jurisdictions.

In Section 6.5.3, curve fitting of the probabilistic cases where incremental additions of hybrid solar and firm generation were examined resulted in more precise firm generation additions where the curve fit was interpolated to meet the EUE standard of 0.002% of load. The firm thermal additions, curve fit to the EUE standard, suggests that firm generation additions ranging between 175 MW to 300 MW compared to the resource blocks previously modeled (200-400 MW). However, 300 MW of firm generation by 2029 is still appropriate to meet reliability standards in the near-term given uncertainties and risks associated with the current generation fleet, uncertainties surrounding renewable development and community acceptance, supply chain of renewable generation equipment, electrification of transportation, among others. This was informed by analyses conducted around the Land Constrained scenario based on stakeholder feedback for remaining developable onshore renewable potential and recognizing that the result of community engagement on REZ may further reduce the technical resource potential that NREL identified in their revised Assessment of Wind and Photovoltaic Technical Potential. Additionally, further opportunities to retire additional fossil-fuel generation can be explored as more renewable resources are brought online over the next decade to ensure that the procurement of at least 300 MW today does not adversely impact cost and reliability over the long-term.

In Section 6.5.4 and 6.5.8, the impact of additional standalone storage was examined: 12-hour duration to proxy a future long duration storage or pumped storage hydro and 2-hour duration to proxy a future demand response program. While both resources improved reliability, their impact was less than if the same capacity for a firm thermal resource was added instead.

In Section 6.5.5, delayed removal of existing fossil-fuel generators was examined and contrasted against the addition of new thermal generators. While delaying the deactivation of existing units can improve system reliability, it is not a 1:1 substitution with a new thermal unit. Greater improvement in reliability was observed at higher levels of new thermal generation even if the total firm generation (existing plus new) was less. This is due to the higher forced outage rates of the existing thermal units to reflect their declining availability as they continue to age, as noted in Section 6.5.1.

In Section 6.5.6, the high load and low load bookends of the IGP forecast were examined with 300 – 400 MW of firm thermal generation and 270 MW of hybrid solar (from the land constrained scenario). At the high load bookend, more than 400 MW of firm generation may be needed to bring LOLE within the US Mainland standard of 0.1, especially if future variable renewables are constrained to 270 MW. At the low load bookend, 400 MW of firm generation is sufficient to meet the reliability standards and further removal of existing thermal generators could be considered; however, 300 MW of firm generation does not result in a reliable system.

In Section 6.5.7, a combined DER and EE freeze case was conducted to get an indicative value of the capacity that is provided by the incremental DER and EE assumed in the forecast. In the absence of the incremental DER and EE that is adopted by year 2029, a new firm addition of nearly 500 MW would be needed for LOLH and EUE to meet the reliability standard. Additional firm generation would still be required to meet LOLE.

In Section 6.5.9, increments of firm generation were considered with the addition of 270 MW of hybrid solar and 400 MW of offshore wind. While 400 MW of offshore wind improved reliability, more than 300 MW of firm generation would still be required to meet reliability for LOLE.

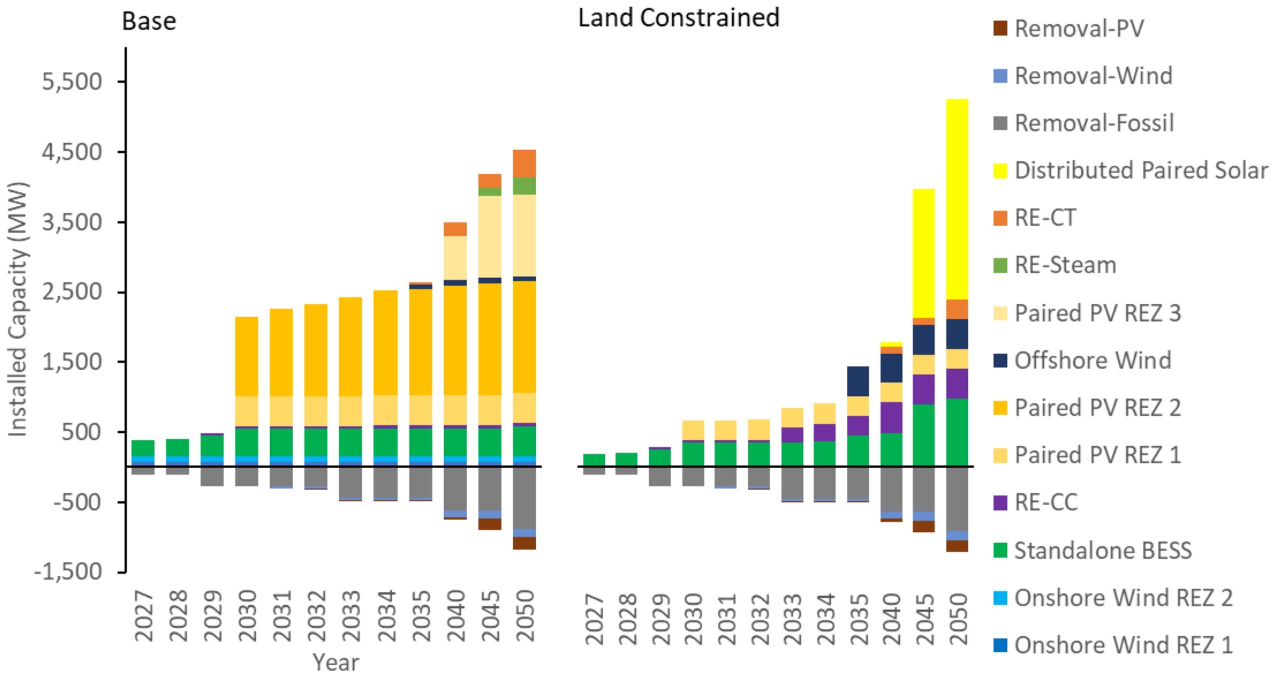
In Section 6.5.10, the reliability of various portfolios was examined when an extended outage of 438 consecutive hours was experienced by each resource type. In portfolios without new firm generation, the extended outage of onshore wind, hybrid solar, and standalone BESS had similar reliability as the base case without an extended outage indicating that the existing thermal resources compensated for the extended outages of those new resources. This is like the Kona Low that was experienced in December 2021 where the variable renewables had reduced output for an entire day. Similarly, in portfolios with new firm generation, if an extended outage was experienced by onshore wind, hybrid solar, and standalone BESS, there is no negative impact to reliability. However, when the new firm thermal generation is on extended outage, the other resources are not able to compensate, resulting in unserved energy.

6.3 Capacity Expansion Plans (RESOLVE)

As described in Section 5, four scenarios were run to determine the optimal least cost resource mix to achieve 100% renewable energy. The "bookend" cases recommended by the TAP provide a wide range of load cases to assess the impact uncertainties in future load may have on the optimal mix of renewable resources given RPS mandates, cost of commercially available technologies, reliability and operational rules. Due to the uncertainty in land use on Oʻahu to develop renewable energy projects, "bookends" on the amount of available land were also tested with the Land Constrained scenario that does not allow new onshore wind projects and limits solar build to 270 MW beyond Stage 1 and 2 projects.

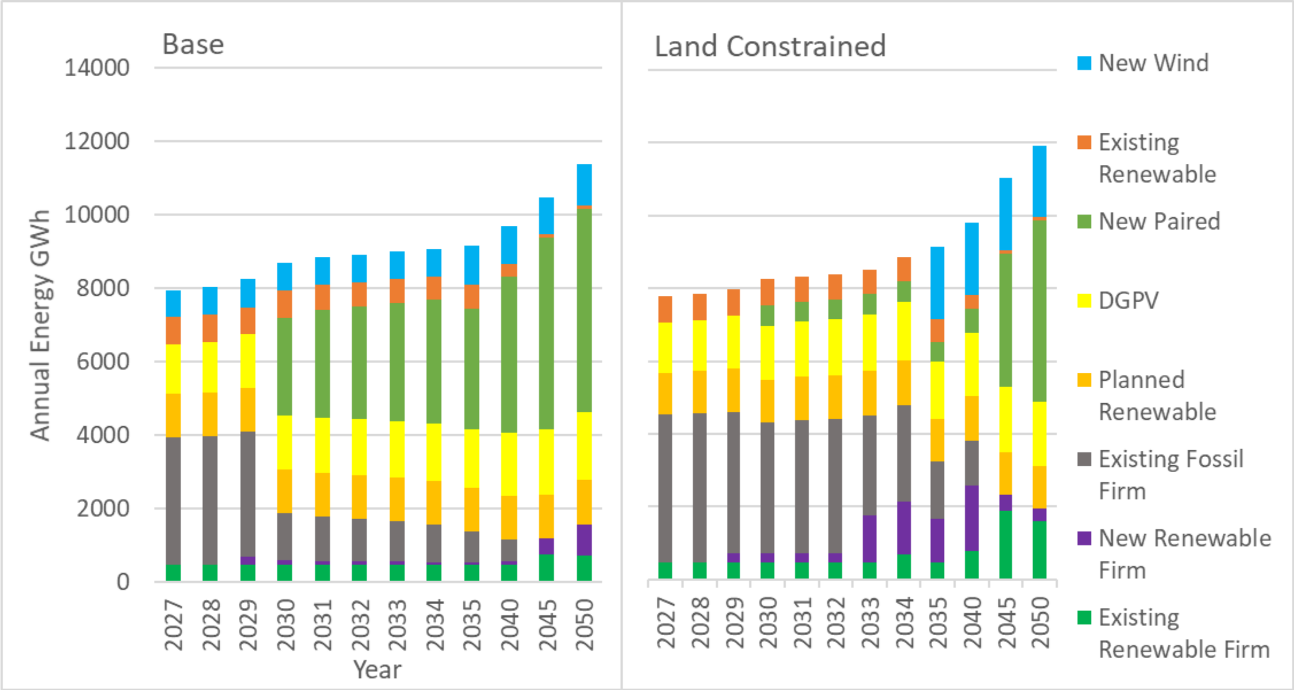
Shown below in Figure 27 are the resource plans from RESOLVE for the Base and Land Constrained scenarios.

Figure 27. Resource plans from RESOLVE for the Base and Land Constrained scenarios



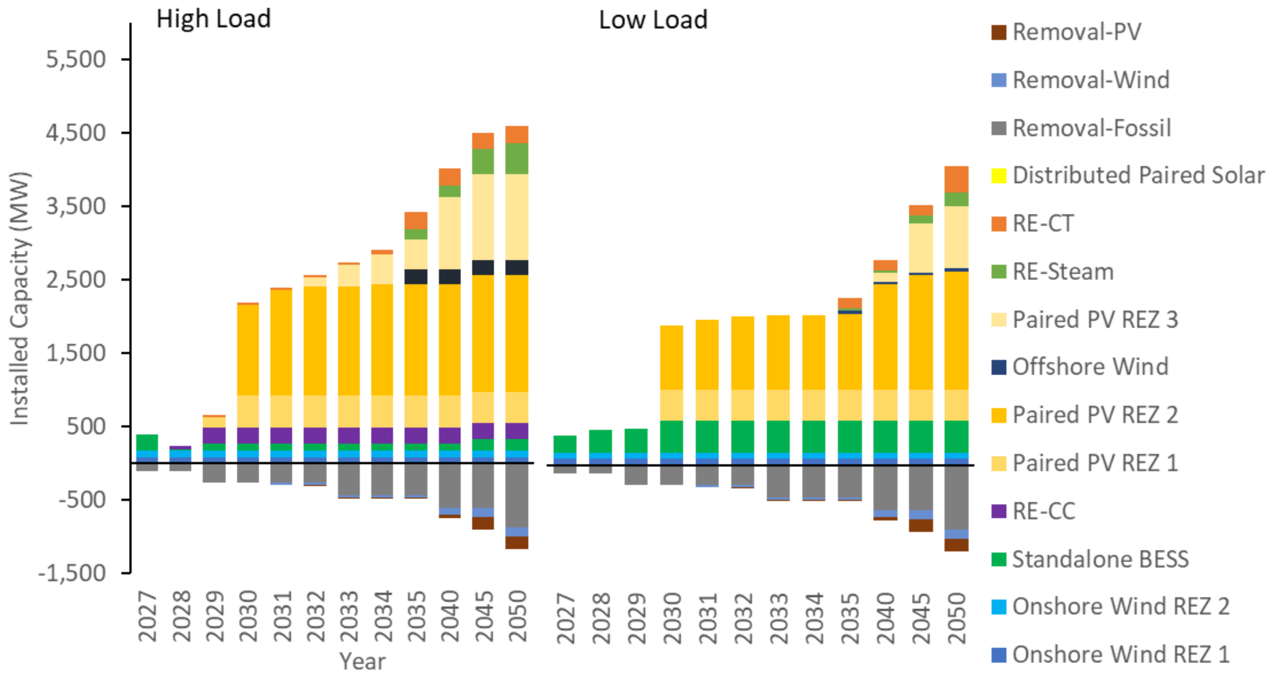
Shown below in Figure 28 are the annual energy (GWh) from RESOLVE for the Base and Land Constrained scenarios.

Figure 28. Projected annual system energy load from RESOLVE for the Base and Land Constrained scenarios



Shown below in Figure 29 are the resource plans from RESOLVE for the High Load and Low Load scenarios.

Figure 29. Resource plans from RESOLVE for the High Load and Low Load scenarios



Shown below in Figure 30 are the annual energy (GWh) from RESOLVE for the High Load and Low Load scenarios.

Figure 30. Projected annual system energy load from RESOLVE for the High Load and Low Load scenarios

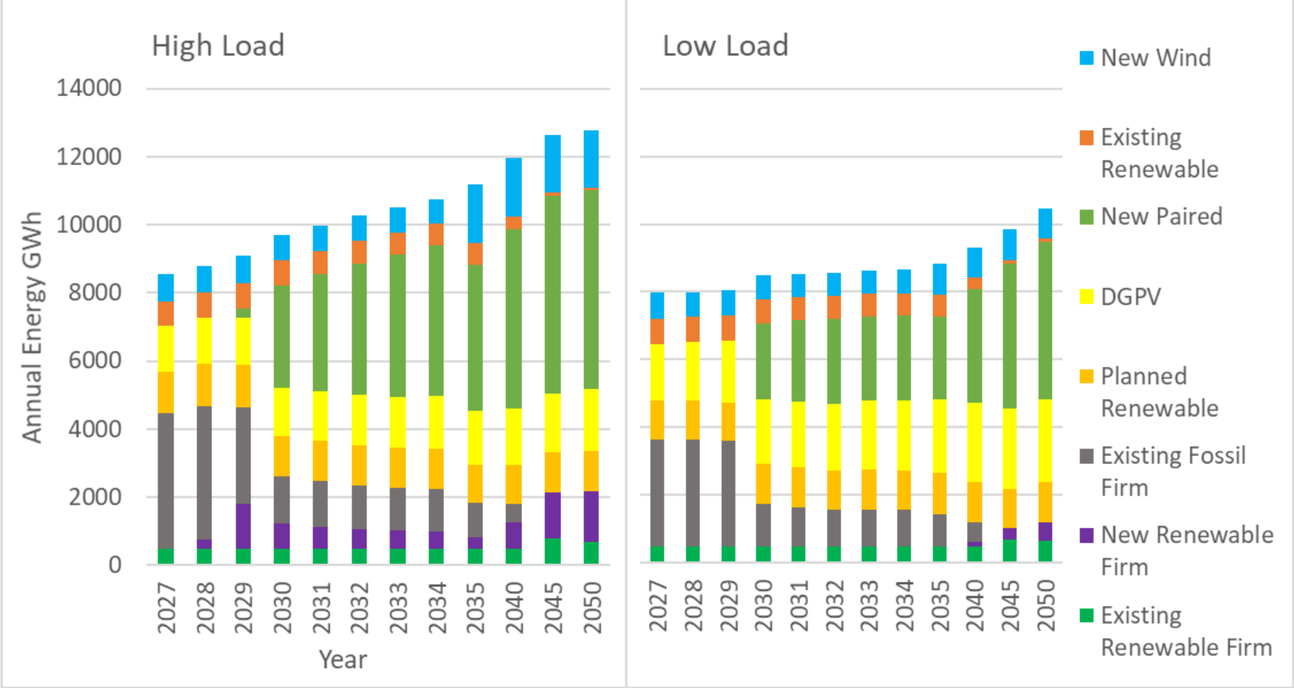


Figure 31. Capacity from RESOLVE for the Base, Low Load, High Load and Land Constrained scenarios

Capacity (MW)	Base			Land Constrained		
	2030	2040	2050	2030	2040	2050
Existing Renewable Firm	77	77	436	77	77	436
New Renewable Firm	35	251	690	39	508	692
Existing Fossil Firm	921	580	0	921	580	0
Planned Renewable	585	585	585	585	585	585
DGPV	803	936	1008	803	936	1008
New Hybrid Solar	1577	2623	3187	270	338	3006
Existing Renewable	336	174	45	336	174	45
New Onshore/Offshore Wind	163	241	241	0	400	400

Capacity (MW)	Low Load			High Load		
	2030	2030	2030	2030	2040	2050
Existing Renewable Firm	77	77	77	77	77	436
New Renewable Firm	0	0	0	250	596	877
Existing Fossil Firm	921	921	921	921	580	0
Planned Renewable	585	585	585	585	585	585
DGPV	1042	1042	1042	776	911	983
New Hybrid Solar and Distributed Solar	1290	1290	1290	1677	2943	3187
Existing Renewable	336	336	336	336	174	45
New Onshore/Offshore Wind	163	163	163	163	368	368

The RESOLVE resource plans for the bookends shown in Figure 31 provide useful information to understand how the selected resources can meet future grid needs, given the uncertainty in forecasted load and assumed variable renewable resource availability. Over the 2027-2050 planning horizon, between the Base, Low Load and High Load scenarios, there is consistency in the types of resources selected. The remaining available onshore, land-based wind resource potential is selected because of its assumed high-capacity factor and low cost. Then starting in 2030, for these cases, between 1,300 and 1,600 MW of hybrid solar are selected in the models. Greater amounts of new firm thermal capacity are built as load increases from the low load to the base to the high load scenarios. This indicates that between the bookends, the grid needs are based on similar resources being selected in the models and that there is only a difference in timing when those resources are built to meet the forecasted load. This also indicates that other load cases are unnecessary since the bookends capture a consistent resource mix across wide-ranging load scenarios.

In the Land Constrained scenario, new land-based renewables are limited. Hybrid solar is built up to its assumed limit of 270 MW and the highest amount of offshore wind is built at 400 MW. In later years of the planning horizon, paired distributed solar is selected, reaching over 90% of the technical rooftop potential for this resource as identified by NREL in their resource potential study. There is a large amount of distributed solar paired with energy storage at the end of the planning horizon, is selected likely for compliance with RPS mandates. The model does not select this resource in earlier years like it does grid-scale facilities likely due to the cost of the distributed solar resource. Future technological advancement in the coming years may also be available to compete with the distributed solar resource through solution sourcing. Lastly, as shown in the energy charts above, the Land Constrained scenario has the slowest transition off fossil-fuels. Additional details on the RESOLVE capacity expansion analysis are available in the appendix to this report.

6.3.1 Renewable Energy Zones

The RESOLVE modeling also demonstrates that the development of renewable energy zones by 2030 is cost-effective as RESOLVE groups 1 and 2 are selected covering West, Central and Windward O'ahu. The northern REZ that covers Wahiawa to the North Shore is selected in later years and has the highest REZ enablement costs. However, it is critically important to note that groups 1 and 2 also include solar on 30% sloped land, as shown below in Figure 32. The Base scenario builds approximately 1,600 MW of grid-scale solar paired with energy storage from RESOLVE REZ groups 1 and 2 in 2030, of which 523 MW is located on slopes less than 15%.

Figure 32. REZ group capacity broken down by slope for solar resources

RESOLVE REZ Group Capacity (MW)	Slope ≤ 15%	15% > Slope ≤ 30%	Total
Group 1 (1, 2, 7 from the REZ Study)	84	426	510
Group 2 (3, 4, 5, 6 from the REZ Study)	439	1,235	1,674
Group 3 (8 from the REZ Study)	435	725	1,160
Total by Slope	**958**	**2,386**	**3,344**

The Stage 3 near-term procurement should seek to maximize the remaining capacity on the transmission system and substation sites without triggering the development of REZ infrastructure. Through IGP and other initiatives, community engagement must continue with affected communities prior to initiating any REZ infrastructure. Market and commercial interests must also be engaged to determine the viability of developing renewable energy projects on these lands, especially on slopes greater than 15%.

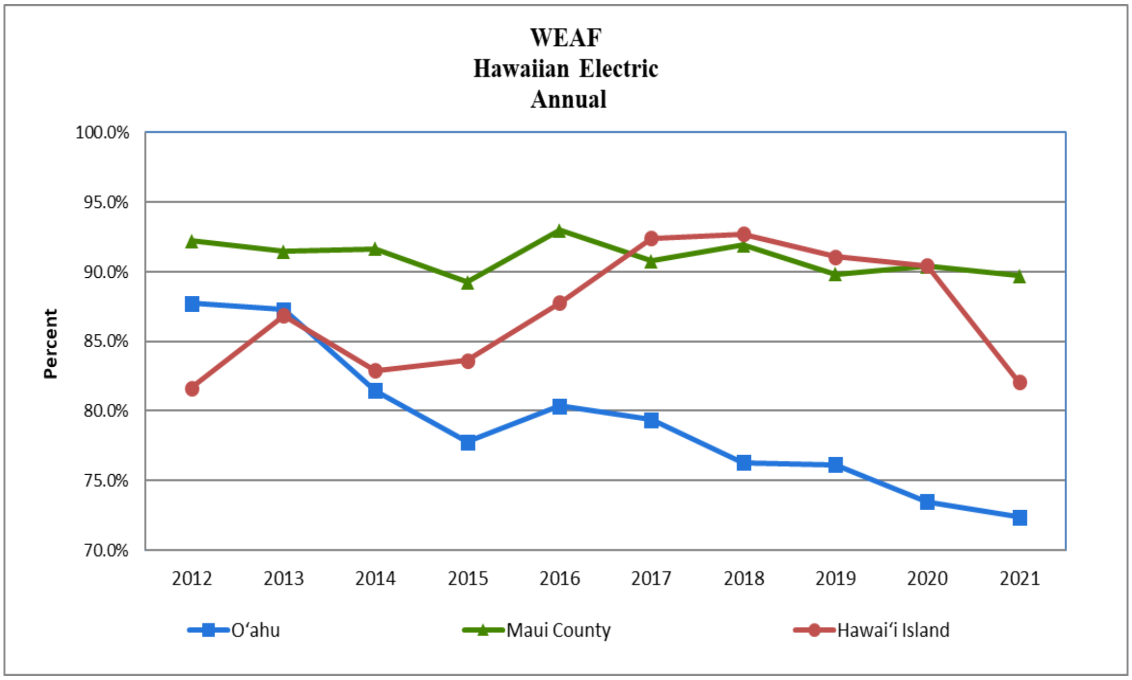
6.3.2 Modeling Iteration and Sensitivity of Thermal Resource Selection to ERM Target and HDC

In the RESOLVE cases modeled in the previous section, existing and new firm generation have an HDC of 1 or 100%, where there are no assumed derates for maintenance or forced outages. Based on TAP feedback, an iteration was conducted between the probabilistic analysis and RESOLVE to verify whether the resource mix changes when firm thermal generation is not given 100% capacity credit towards meeting the ERM. This would mitigate any bias the model may have towards firm thermal generation. A thermal HDC was applied in RESOLVE to represent the availability of thermal units after both types of outages. For existing units, the 2021 Weighted Equivalent Availability Factor (WEAF) was used. This metric is the percentage of time a fleet of generating units is available to generate electricity, weighted for generator size where larger generators have a greater effect on WEAF, and includes planned and unplanned outages. The historical WEAF is reported quarterly as part of the Key Performance Metrics. For new CTs, the net of the forced outage rate (1.3%) and maintenance outage rate (1.3%) was used.

- O‘ahu existing firm generation HDC = 72.37%
- O‘ahu new firm generation HDC = 97.4%

The existing firm generation HDC reflects the declining availability of the existing thermal fleet, as shown in the historical WEAF in Figure 33, and is a complementary assumption to the increased forced outage rate that was discussed in Section 6.5.1.

Figure 33. Historical WEAF by county



Several cases were evaluated with the firm HDC, including cases where the ERM target was varied in 10% increments.

- Base_wKPLPMahi
  - Base case modeled in RESOLVE, KPLP and Mahi added as planned resources after optimization
  - Existing firm HDC = 100%, New firm HDC = 100%, and ERM Requirement = 30%
- Base.v2
  - Base case without KPLP and Mahi
  - Existing firm HDC = 100%, New firm HDC = 100%, and ERM Requirement = 30%
- Base.v3_30ERM
  - Base.v2 with HDC applied to firm units
  - Existing firm HDC = 72.37%, New firm HDC = 97.4%, and ERM Requirement = 30%
- Base.v3_20ERM
  - Base.v2 with HDC applied to firm units
  - Existing firm HDC = 72.37%, New firm HDC = 97.4%, and ERM Requirement = 20%
- Base.v3_10ERM
  - Base.v2 with HDC applied to firm units
  - Existing firm HDC = 72.37%, New firm HDC = 97.4%, and ERM Requirement = 10%
- Base.v3_0ERM
  - Base.v2 with HDC applied to firm units
  - Existing firm HDC = 72.37%, New firm HDC = 97.4%, and ERM Requirement = 0%
- Land Constrained
  - Base case without future onshore wind, 270 MW limit on paired PV+BESS, no biomass, and 400 MW limit on offshore wind.
  - Firm HDC = 100% and ERM Requirement = 30%
- LC.v3_10ERM
  - Land Constrained without KPLP and Mahi, with HDC applied to firm units
  - Existing firm HDC = 72.37%, New firm HDC = 97.4%, and ERM Requirement = 10%

The results of the firm HDC cases are summarized below.

Figure 34. Buildout sensitivity using firm HDC and different ERM targets

Year 2030	Base_wKPLP Mahi	Base.v2	Base.v3_30ERM	Base.v3_20ERM	Base.v3_10ERM	Base.v3_0ERM	Land Constrained	LC.v3_10ERM
Existing firm HDC (%)	100	100	72.37	72.37	72.37	72.37	100	72.37
New firm HDC (%)	100	100	97.4	97.4	97.4	97.4	100	97.4
ERM Requirement (%)	30	30	30	20	10	0	30	10
New Firm (selected by RESOLVE)	35	264	521	408	300	213	39	342
Existing Firm	1,175	967	967	967	967	967	967	967
Standalone PV	0	0	0	0	0	0	0	0
Paired PV (Hybrid Solar)	1,577	1,640	1,401	1,556	1,594	1,741	270	270
Onshore Wind	163	163	163	163	163	163	0	0
Offshore Wind	0	0	0	0	0	0	0	0
Standalone Storage (MW/MWH)	379 MW / 712 MWh	66 MW / 124 MWh	67 MW / 127 MWh	64 MW / 122 MWh	61 MW / 115 MWh	75 MW / 140 MWh	321 MW / 600 MWh	14 MW / 26 MWh
Paired Storage (MW/MWH)	1,577 MW / 4,461 MWh	1640 MW / 5,100 MWh	1401 MW / 3,639 MWh	1,556 MW / 4,502 MWh	1,594 MW / 4,770 MWh	1,741 MW / 5,613 MWh	270 MW / 270 MWh	270 MW / 270 MWh

Across the Base cases, a high amount of hybrid solar is selected. In cases where the ERM target was adjusted downward from 30%, a relatively constant amount of new hybrid solar and new firm thermal generation was selected in RESOLVE with hybrid solar increasing and firm thermal decreasing as the target trended downward. In the Base case without KPLP, new firm generation is selected by RESOLVE to replace the capacity that is lost when this unit is removed. Importantly, with some ERM target to plan for, RESOLVE selects between 300 – 500 MW of new firm generation. In the Land Constrained case where new hybrid solar was limited, increased amounts of firm generation are selected with a lower ERM target and firm HDC. The results of the thermal HDC testing are consistent with the results of the probabilistic resource adequacy where a similar amount of new thermal capacity in the range of 300 – 400 MW was identified.

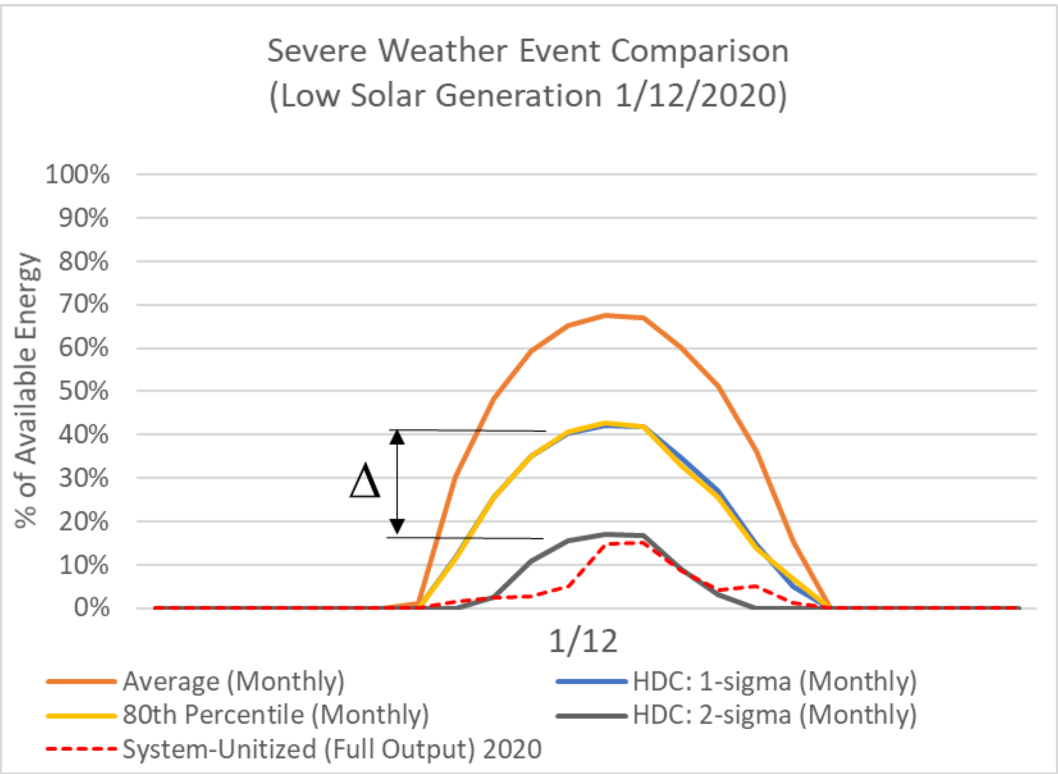
In summary, the ERM and HDC approach does not bias the optimal mix towards firm thermal generation as similar amounts of hybrid solar are selected compared to the original set of RESOLVE cases modeled. The optimal resource mix generally does not change except for the amount of firm generation that is selected depending on the level of ERM. These cases also produce firm generation amounts that are consistent with the probabilistic analyses that indicates somewhere between 200-500 MW of firm generation is needed depending on the desired level of reliability.

6.4 Resource Adequacy – Energy Reserve Margin

Hawaiian Electric performed an ERM analysis in PLEXOS using the Base, Low Load, High Load and Land Constrained resource plans produced by RESOLVE. Firm resources selected by RESOLVE were removed in the ERM analysis to determine the actual shortfall need (i.e., unserved energy) in magnitude (MW) and duration (hours). The ERM analysis accounts for the capacity value from the future variable renewable and storage resources selected by RESOLVE.

As noted earlier, the 1-sigma HDC and 30% ERM target were used in this analysis. The 1-sigma HDC is similar to the 80th percentile HDC that was ultimately adopted following discussion with the TAP. Because this analysis was started at the end of 2021, the analysis assumes the use of 1 sigma HDC and 30% ERM which is different than recent Commission guidance issued in D&O No. 38482 on June 30, 2022. While the methodology to calculate the HDC uses a typical day-of-the-month approach to expand the available datapoints used in the HDC calculation, it also means that all days within a month will have the same hourly profile. Therefore, the current HDC has no day-to-day variability and may overstate the capacity contributions of PV and wind on certain days.

Figure 35. Comparison of solar HDC calculations

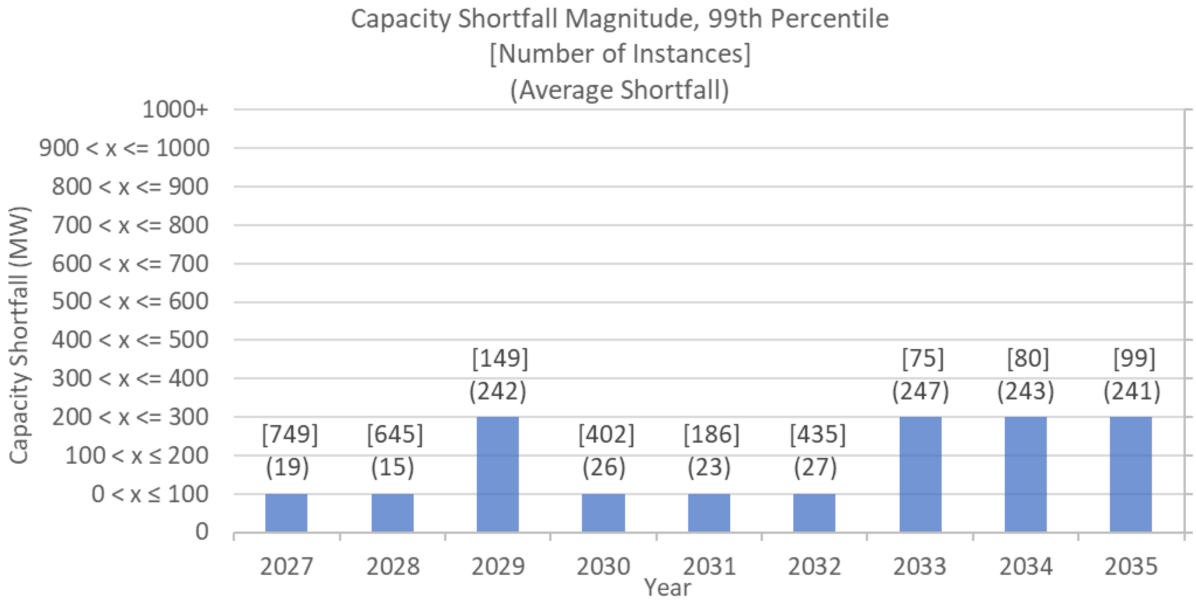


- Significant overlap of 1-sigma and 80th percentile profiles
- However, 1-sigma or 80th percentile would overstate the available energy on this day.

Figure 35 compares the 80th percentile, 1-sigma, and 2-sigma solar HDCs calculated for a typical day of the month as discussed with the TAP on January 20, 2022. On this example day, the 1-sigma and 80th percentile HDCs show good alignment with each other. Still, they are higher than the simulated PV production using NREL's weather dataset, shown by the red dotted line, and the 2-sigma HDC that more closely matches the NREL's simulated production.

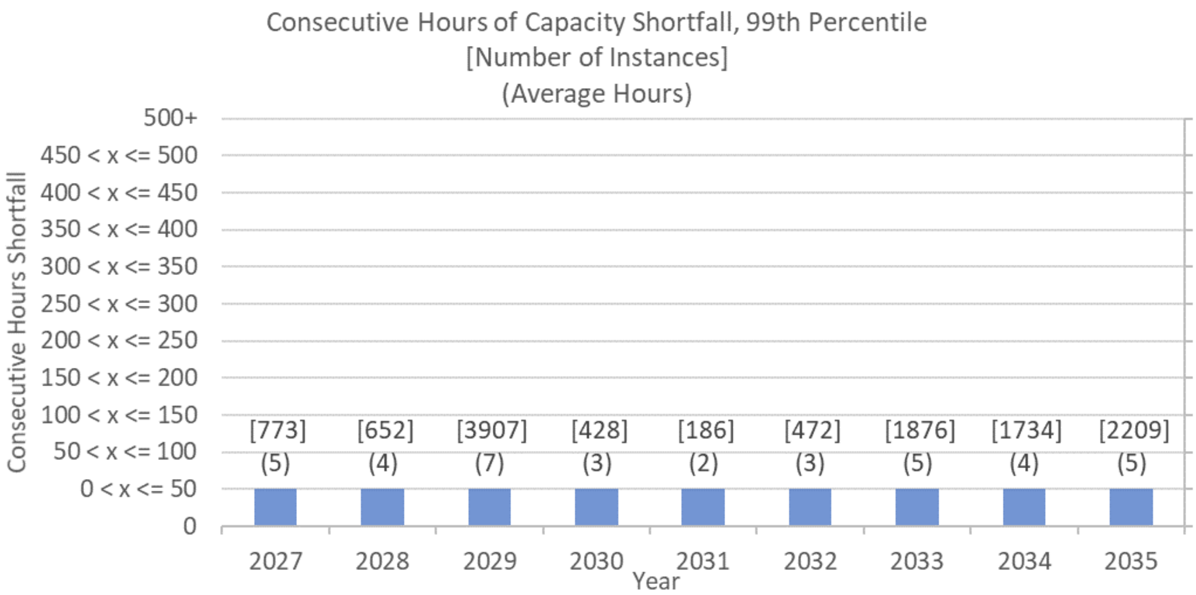
Shown below in Figure 36 is the number of instances of a given capacity shortfall each year and in parentheses is the average capacity shortfall for the range. 99th percentile means 99% of all shortfall instances are less than or equal to the capacity shown. The 99th percentile is used here to define the capacity shortfall to include most instances except for the most extreme outliers. Using 2029 as an example, 99% of the capacity shortfall is 300 MW or less, there are 149 instances of capacity shortfall between 200 MW and 300 MW, and the average shortfall in the 200 MW to 300 MW range is 242 MW. The capacity need identified is intended to reduce the risks of over-procuring by accounting for contributions from future variable renewables and storage toward meeting future capacity needs and by removing the extreme capacity shortfalls.

Figure 36. Annual 99th percentile capacity shortfall, Base Scenario, with [number of instances] and (average shortfall)



Similar information is shown below in Figure 37 for the 99th-percentile of the number of instances of consecutive hours of capacity shortfall each year. Using 2029 as an example, there are 3,907 instances of capacity shortfall up to 50 hours long, and the average shortfall duration is seven hours. These numbers represent lowest 99% of all instances of capacity shortfall in 2029. The 99th percentile is used here to define all instances except for the most extreme outliers.

Figure 37. Annual 99th percentile hours of capacity shortfall, Base Scenario, with [number of instances] and (average consecutive hours)



A summary of the number of instances of a given capacity shortfall in 2029 and 2033 (key years where firm capacity is assumed to be removed from the system) is shown in Figure 38 and Figure 39, respectively, for the Base, Low Load, High Load and Land Constrained scenarios.

Figure 38. Histograms of capacity shortfall in 2029 grouped by scenario and shortfall magnitude

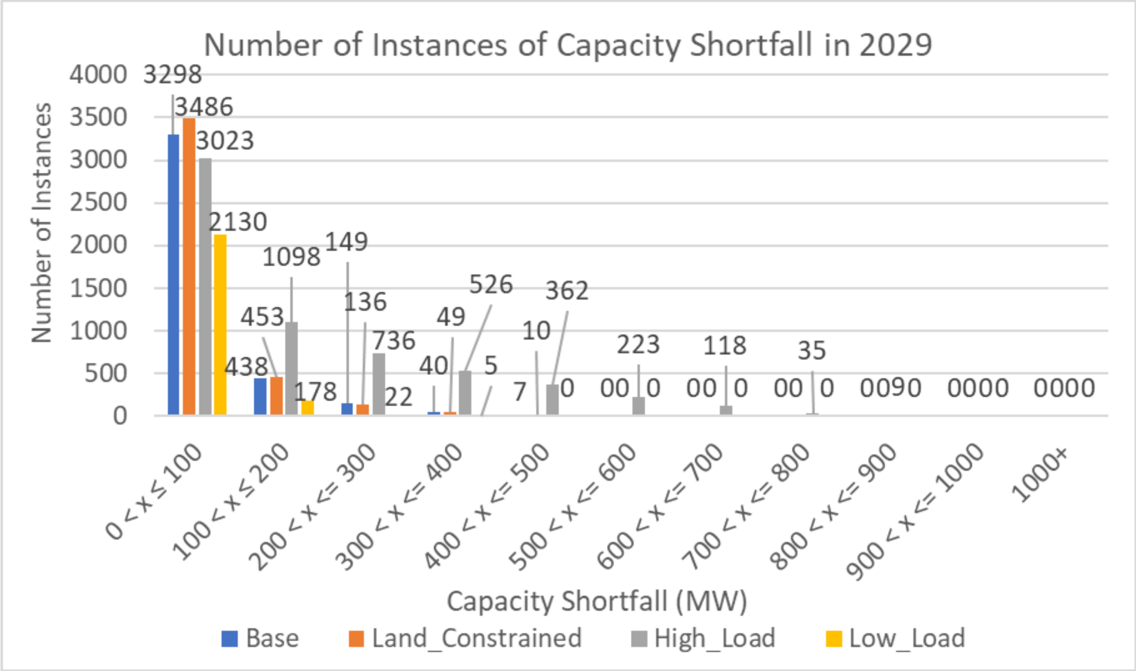
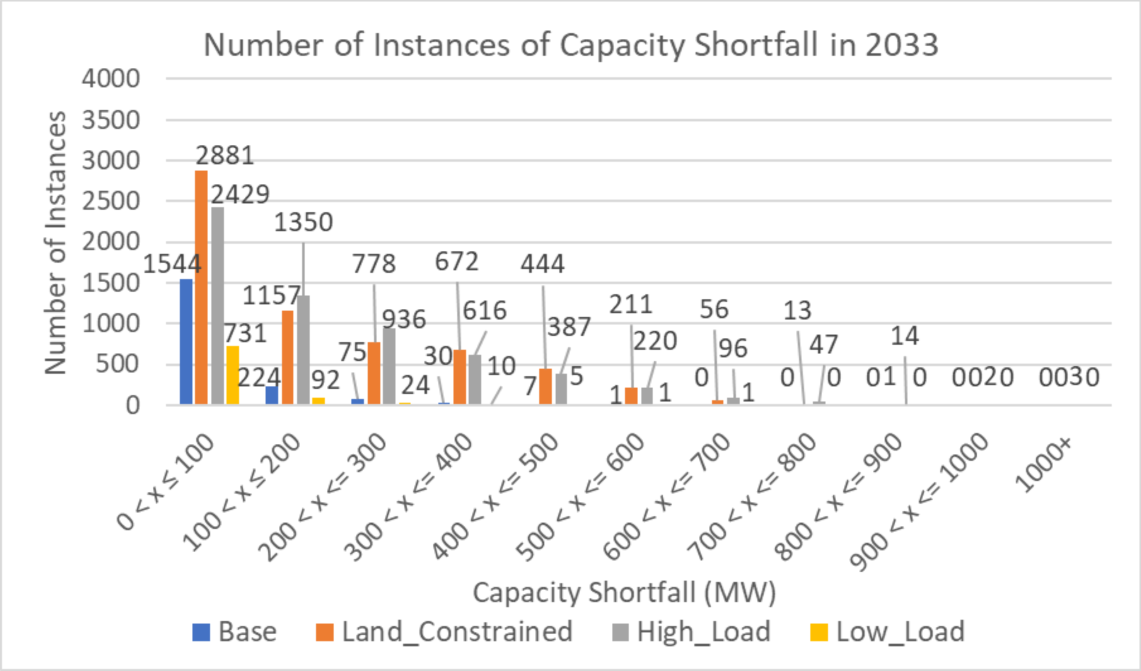


Figure 39. Histograms of capacity shortfall in 2033 grouped by scenario and shortfall magnitude



A summary of the number of instances of a given consecutive hours shortfall in 2029 and 2033 is shown in Figure 40 and Figure 41, respectively, for the Base, Low Load, High Load and Land Constrained scenarios.

Figure 40. Histograms of capacity shortfall in 2029 grouped by scenario and shortfall duration

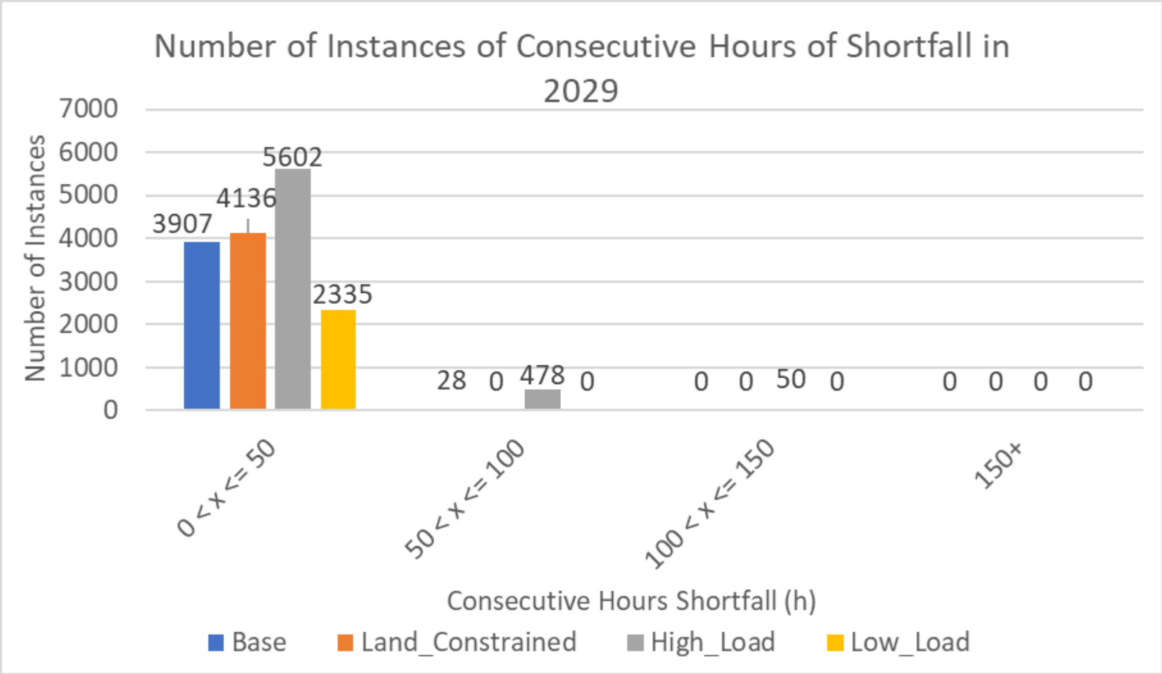
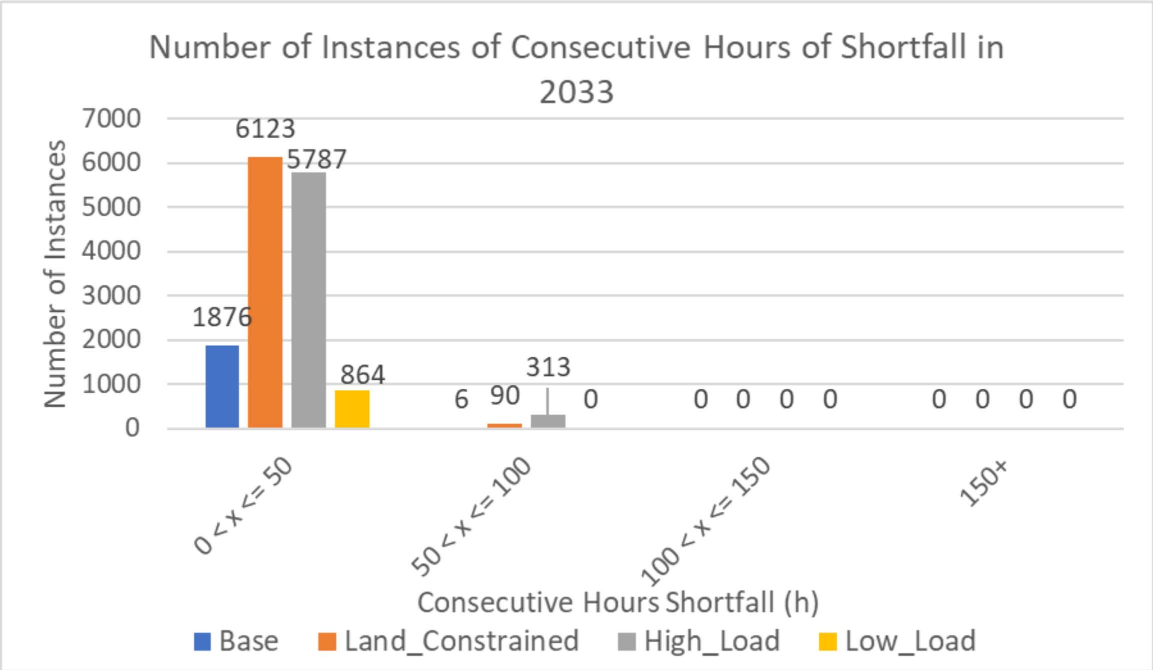


Figure 41. Histograms of capacity shortfall in 2033 grouped by scenario and shortfall duration



The High Load bookend scenario has higher capacity needs on a magnitude and duration basis because of the higher forecasted loads associated with increased EV uptake and reduced DER and EE uptake. This scenario provides useful information to inform how much additional capacity would be needed to provide further assurance that the system can reliably serve load amidst customer trends and state and federal policies that may drive EV adoption and thus increase load that Hawaiian Electric would need to serve. It also provides insight into the system needs should customer adoption of DER and EE fall short of projections that are embedded in the load forecast. Differences between the Base and other planning scenarios become more apparent once 170 MW of fossil-fuel generation is removed from service in 2029. Since the Land Constrained scenario does not allow for further onshore wind development and reduces the amount of solar development that can occur compared to the Base scenario, the number of hours of shortfall and capacity shortfall is higher in the Land Constrained scenario than the Base scenario.

6.4.1 ERM Sensitivity with Additional Generation Removals

An ERM sensitivity analysis was performed in PLEXOS using the Base resource plan shown in Figure 27, but in this scenario, the 208 MW KPLP was removed in 2029, and the largest Stage 2 project, 120 MW Mahi Solar, was removed. Since these are the two largest capacity firm generation and solar projects, respectively, a sensitivity was run to determine their impact on the ERM.

Similar to the other cases examined for ERM, the firm resources selected by RESOLVE were removed in the ERM analysis to determine the shortfall that any future firm resource addition would need to address. Shown below in Figure 42 is the number of instances of a given capacity shortfall each year and in Figure 43 is the number of instances of consecutive hours of capacity shortfall each year.

Figure 42. Annual 99th percentile capacity shortfall, Base_noKPLP_noMahi scenario, with [number of instances] and (average shortfall)

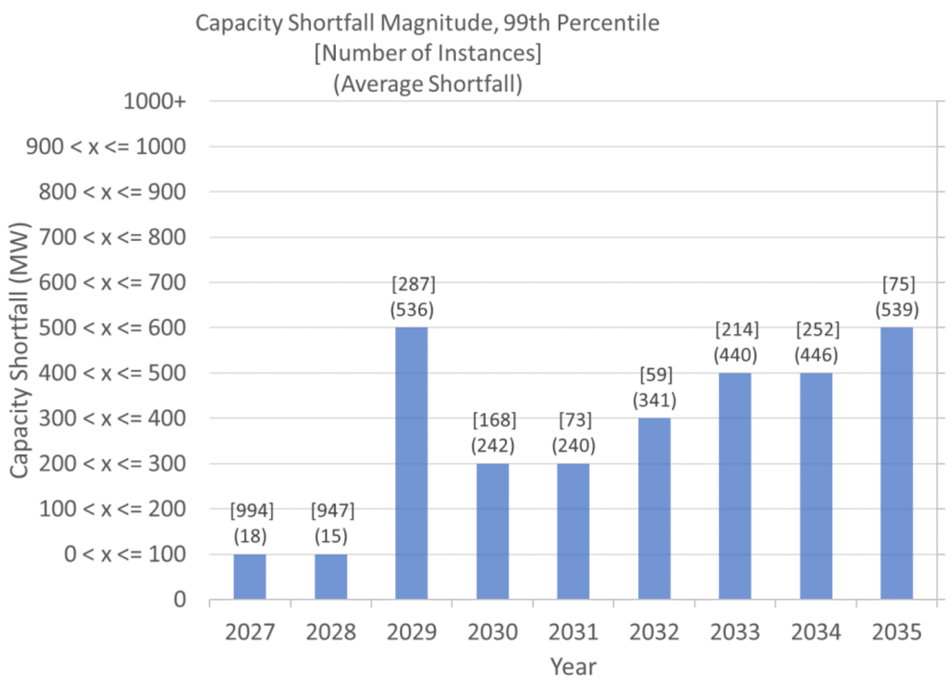
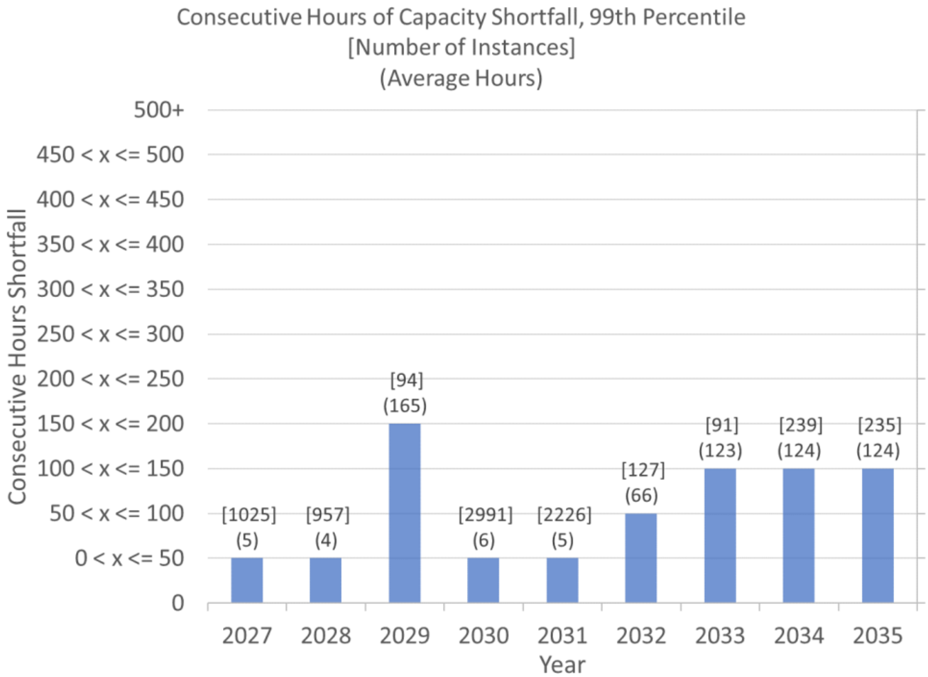


Figure 43. Annual 99th percentile hours of capacity shortfall, Base_noKPLP_noMahi scenario, with [number of instances] and (average shortfall duration)



In the Base case that removed KPLP and Mahi Solar from the resource plan, the removal of Mahi Solar does not appear to materially change the need as the capacity and duration in 2027 and 2028 is similar to the Base case. However, the removal of KPLP in this case dramatically increases the capacity and duration of the shortfalls from 2029. By comparing Figure 36 and Figure 42, it is evident that removal of KPLP and Mahi Solar increases the average capacity shortfall in 2029 by 294 MW, from 242 MW to 536 MW. By comparing Figure 37 and Figure 43, it is evident that removal of KPLP and Mahi Solar increases the average consecutive hours shortfall in 2029 by 158 hours, from 7 hours to 165 hours. This indicates that the removal of this large thermal generator has an outsized impact on future reliability.

Due to the amount of time needed to conduct a competitive procurement for a firm generation resource, 2029 is the earliest estimated date that a firm resource could be installed. In the Base_NoKPLP_NoMahi case, in 2029, 99% of the shortfall is less than 600 MW, and the average shortfall for all instances in the 500MW to 600MW range is 536MW.

Based on the analytical results, a firm thermal unit appears appropriate to fulfill the capacity needs identified in this analysis based on the long duration of the needs shown in the ERM analysis. In the Base_NoKPLP_NoMahi case, in 2029, 99% of the duration required is less than 200 consecutive hours and the average duration for all instances in the 150 to 200 consecutive hour range is 167 consecutive hours. The long-duration need is much longer than could be reasonably met with battery energy storage or other energy storage resources but could be met by a firm thermal resource with a renewable fuel supply.

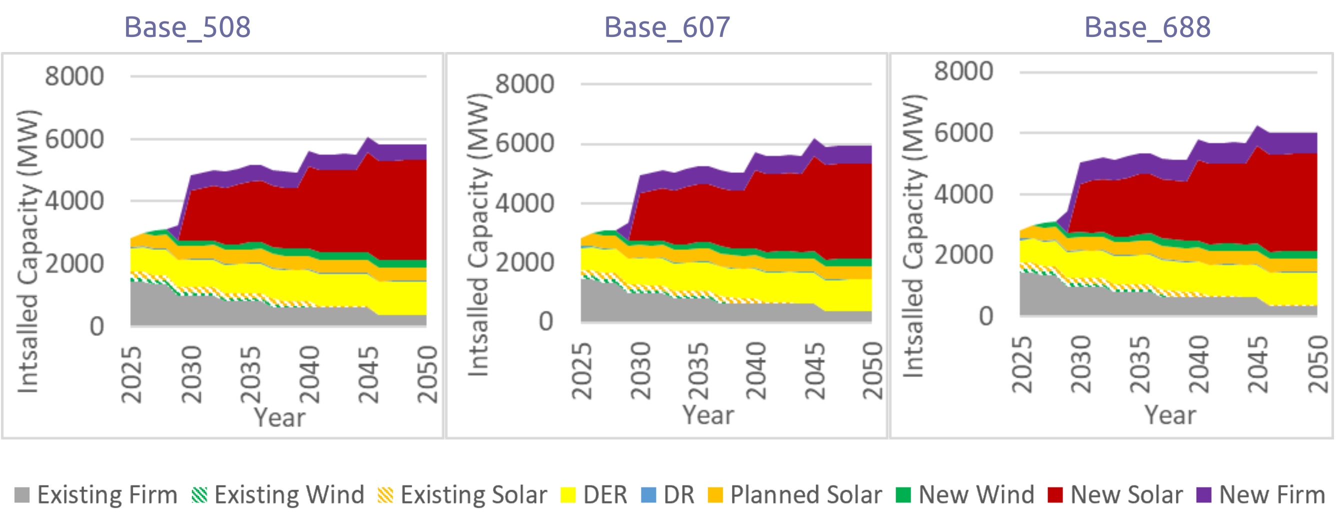
6.4.2 ERM Iteration to Validate Resource Adequacy Grid Needs

Hawaiian Electric performed an iteration of the ERM analysis to determine the ERM need. Based on the analysis where no new resources are added to the system, Hawaiian Electric tested firm capacity additions ranging from 500 to 700 MW and included firm fossil-fuel generation removals as indicated in the inputs and assumptions in years 2027, 2029 and 2033.

500 MW was determined based on the Base scenario 99th percentile showing capacity shortfalls between 200-300 MW (an average of 242 MW) and the sensitivity with KPLP removed showing capacity shortfalls between 500-600 MW (an average of 536 MW). The higher end target of 700 MW is based on year 2033 (with simulated removal of another 170 MW of firm fossil-fuel generation) that capacity shortfalls in the Land Constrained and High Load scenarios are seen in excess of 500 MW, before the assumed removal of the 208 MW KPLP plant. In other words, if KPLP is assumed to be in-service through the planning horizon, the ERM shortfalls fall between 300-500 MW. Under the assumption that KPLP is not in-service, shortfalls range between 500-700 MW. This section examines the ERM need based on these ranges to inform any potential capacity grid needs.

In the Base and Land Constrained cases, planned additions of thermal resource were added in 2029. These ERM scenarios add 508, 607, and 688 MW of firm generation (with Mahi Solar and KPLP removed). In the 508 case, 300 MW of combustion turbine and 208 MW of combined cycle were added. In the 607 case, 300 MW of combustion turbine, 208 MW of combined cycle, and 99 MW of internal combustion engine were added. In the 688 case, 300 MW of combustion turbine, 208 MW of combined cycle, and 180 MW of biomass were added. Shown below in Figure 44 is the installed capacity trend for various resource categories for the Base_508, Base_607 and Base_688 scenarios, respectively.

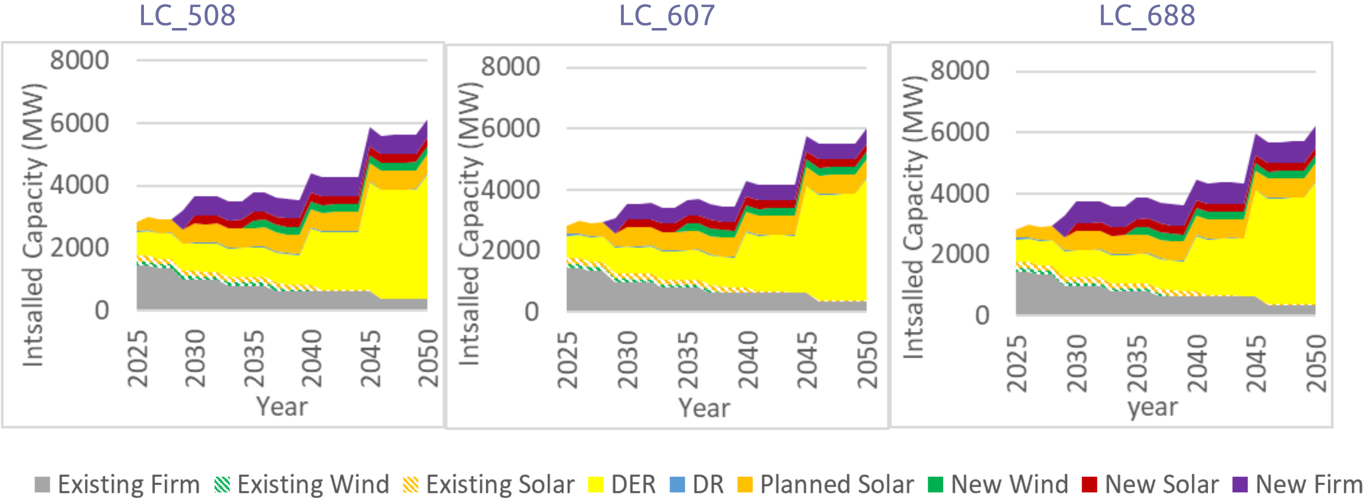
Figure 44. Installed capacity trends for resource categories by scenario



As the existing fossil-fuel firm generation in gray declines over time with the removal of existing thermal generating units from normal service over the planning period, the replacement thermal capacity of new renewable firm in purple is still much less than the variable renewables considered in the portfolio.

The same firm capacity was installed in the Land Constrained (LC) case. Shown below in Figure 45 is the installed capacity trend for various resource categories for the LC_508, LC_607 and LC_688 scenarios, respectively. The Land Constrained scenario, which limits the development of future grid-scale renewables, relies upon distributed solar in the later years of the planning horizon.

Figure 45. Installed capacity trends for resource categories by scenario



A summary of the number of instances of a given capacity shortfall in 2029 and 2033 is shown in Figure 46 and Figure 47, respectively, for the three different Base scenarios and three different Land Constrained scenarios.

Figure 46. Histograms of capacity shortfall in 2029 grouped by scenario and shortfall magnitude

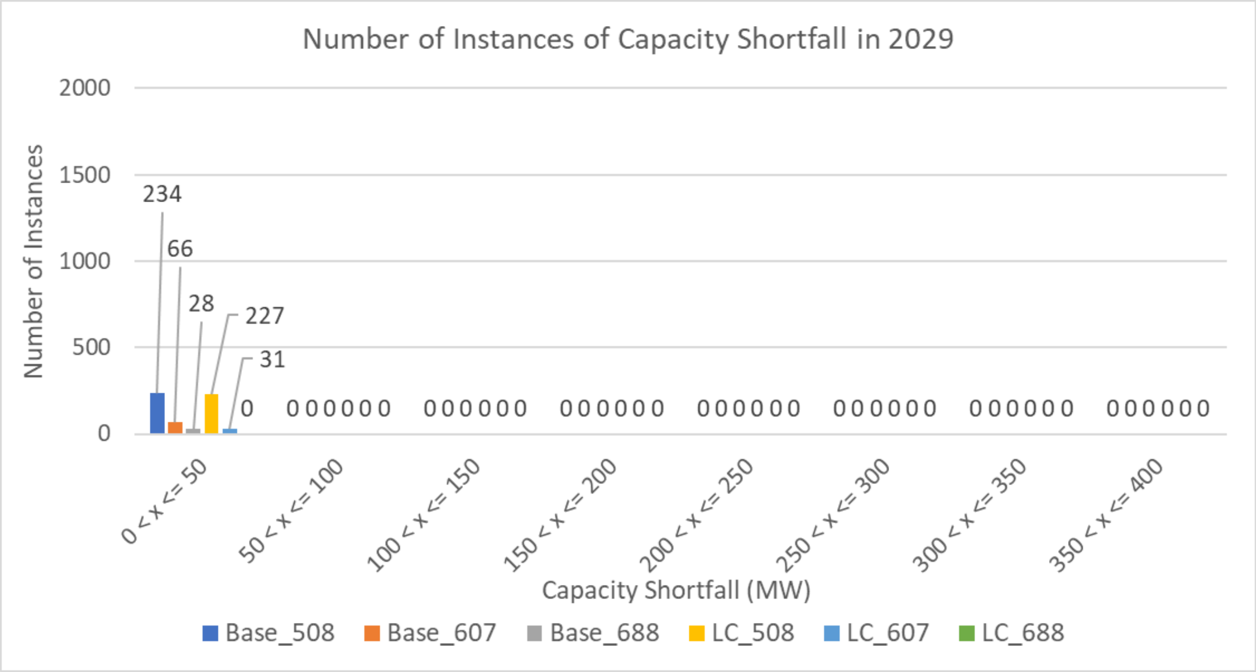
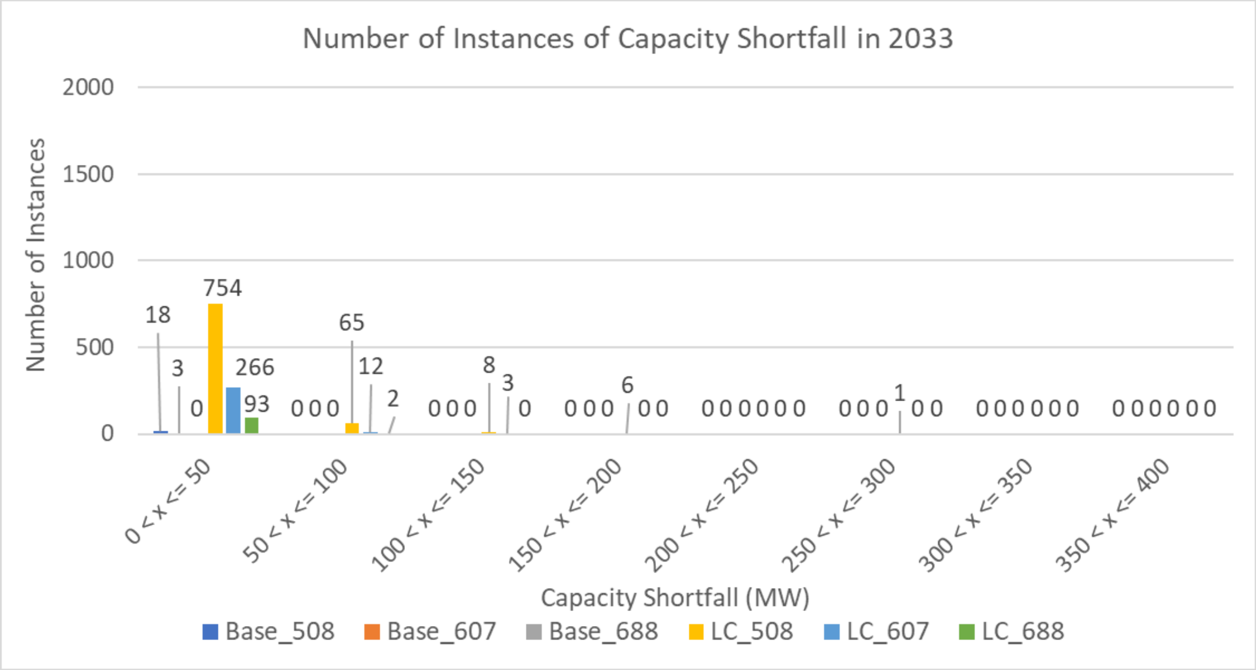


Figure 47. Histograms of capacity shortfall in 2033 grouped by scenario and shortfall magnitude



A summary of the number of instances of a given consecutive hours shortfall in 2029 and 2033 is shown in Figure 48 and Figure 49, respectively, for the three different Base scenarios and three different Land Constrained scenarios.

Figure 48. Histograms of capacity shortfall in 2029 grouped by scenario and shortfall duration

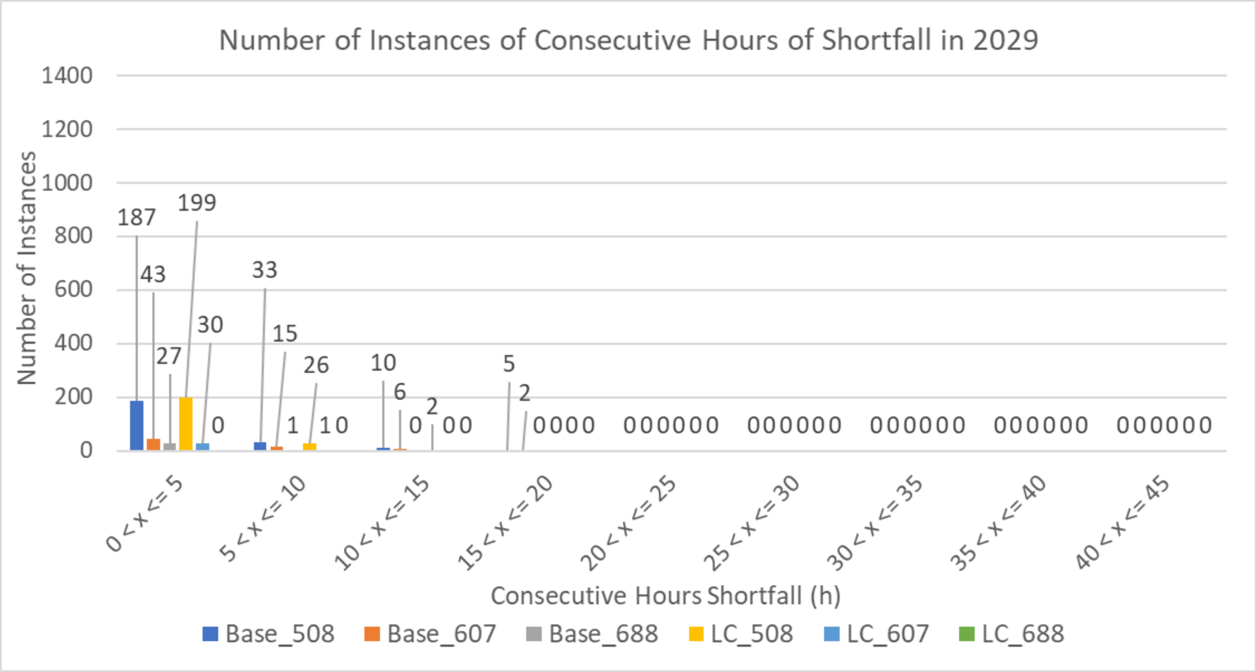
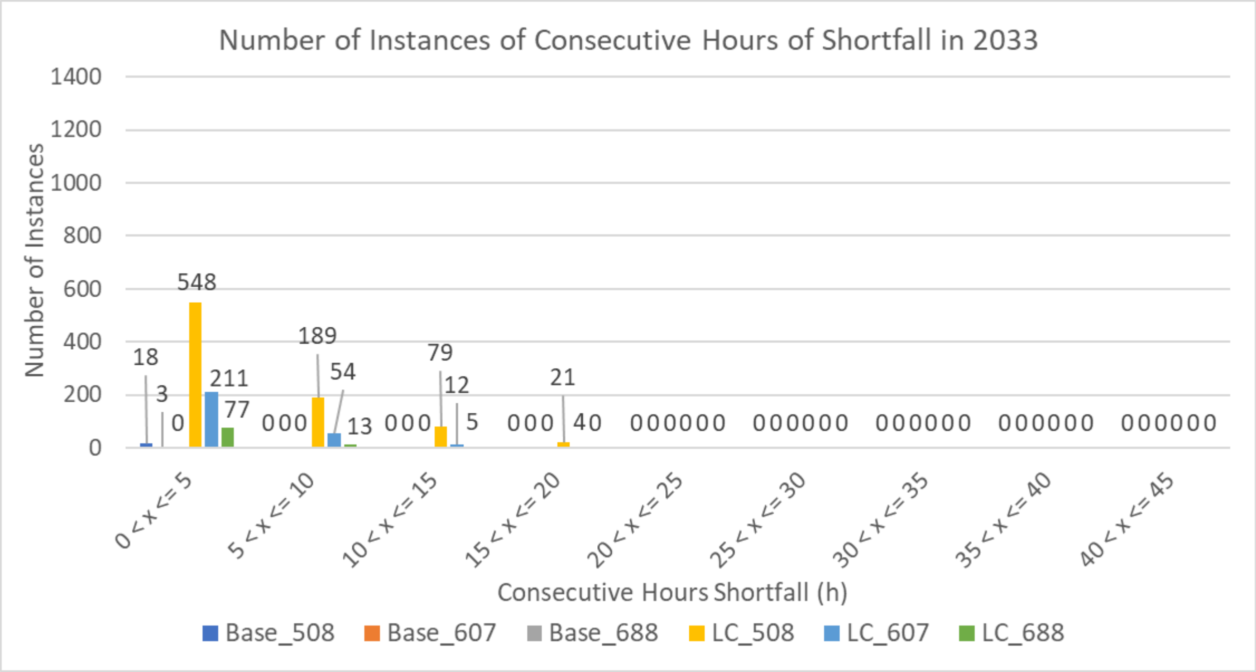


Figure 49. Histograms of capacity shortfall in 2033 grouped by scenario and shortfall duration



When the firm resource is added in 2029, the capacity shortfall and number of instances of shortfall decreases. Similarly, when the firm resource is added in 2029, the consecutive hours shortfall and number of instances of shortfall decreases. The Base scenario also has less shortfall, both in magnitude and frequency, than the Land Constrained scenario due to the higher amounts of renewables (wind and paired solar) added.

Shown below in Figure 50 is a detailed look of the capacity shortfall for the three different Base scenarios and three different Land Constraint scenarios in 2029. As expected, as the size of the firm capacity increases, there is less capacity shortfall.

Figure 50. Year 2029 hourly capacity shortfall. Base and Land Constrained scenarios

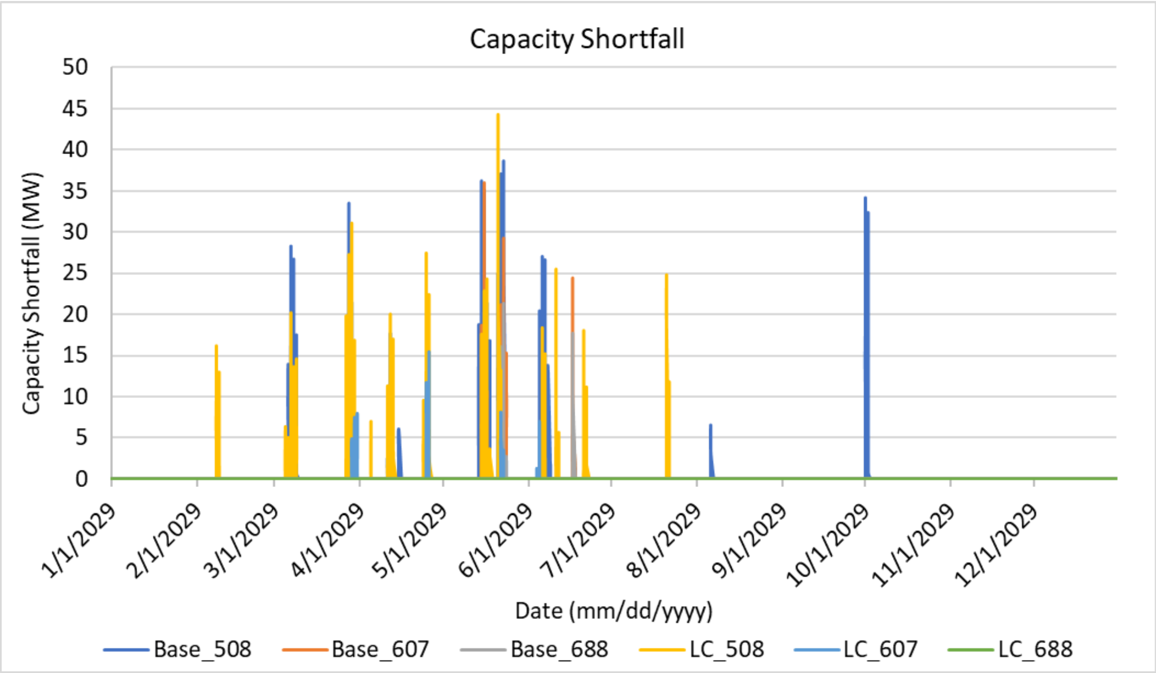


Figure 51 and Figure 52 are the dispatch for a high-renewable day in 2029 and low-renewable day in 2029, respectively. Note that this is the dispatch in the ERM analysis, and therefore, variable renewable production is defined by the HDC and is not representative of the dispatch of the new firm units during normal operation. As shown in Figure 51, even on a day with high renewable energy, the new firm generators are needed to meet capacity need. This becomes even more evident on the low-renewable days shown in Figure 52. Even with the large number of renewables added in 2030, the new firm generators are still needed to help meet the capacity requirement as shown in Figure 51 and Figure 52.

Figure 51. Daily chart – ERM simulation – Base_508 scenario– High renewable day

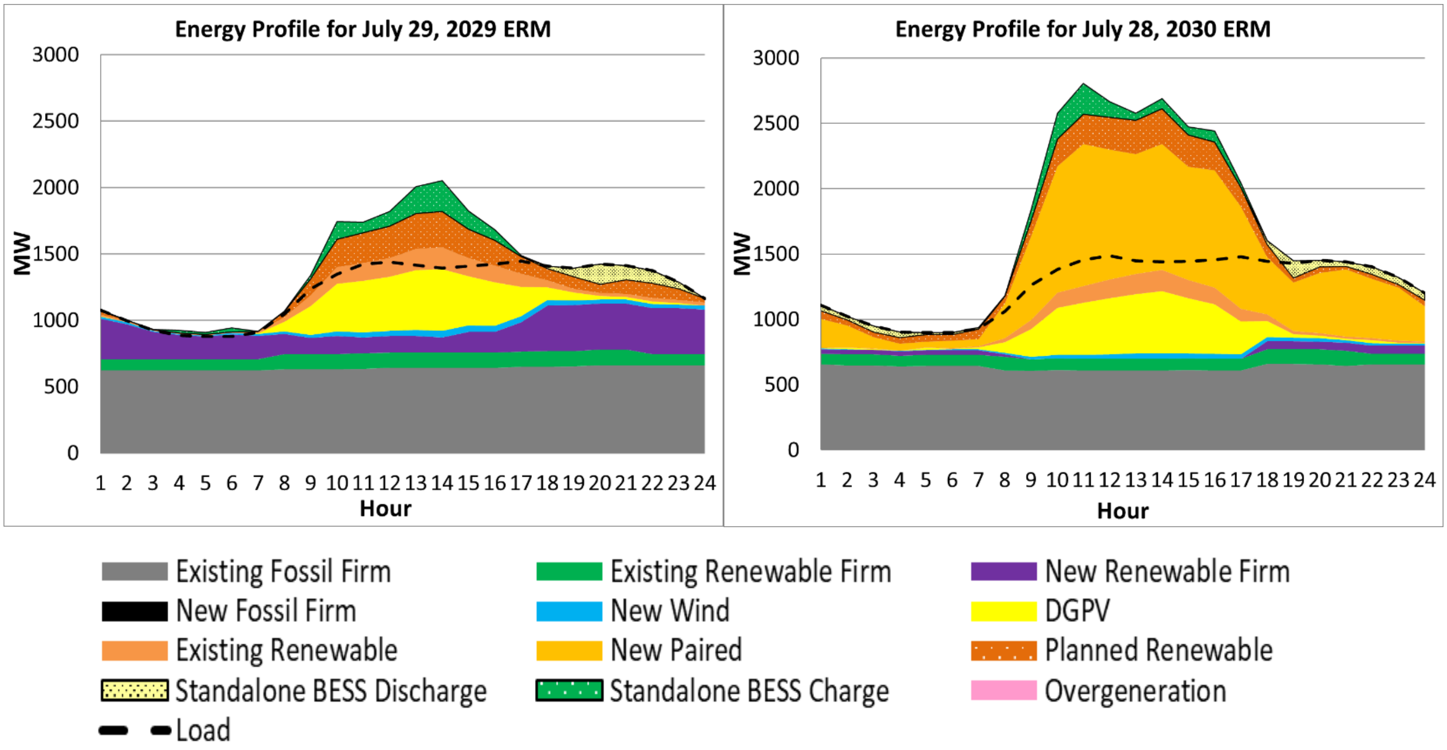
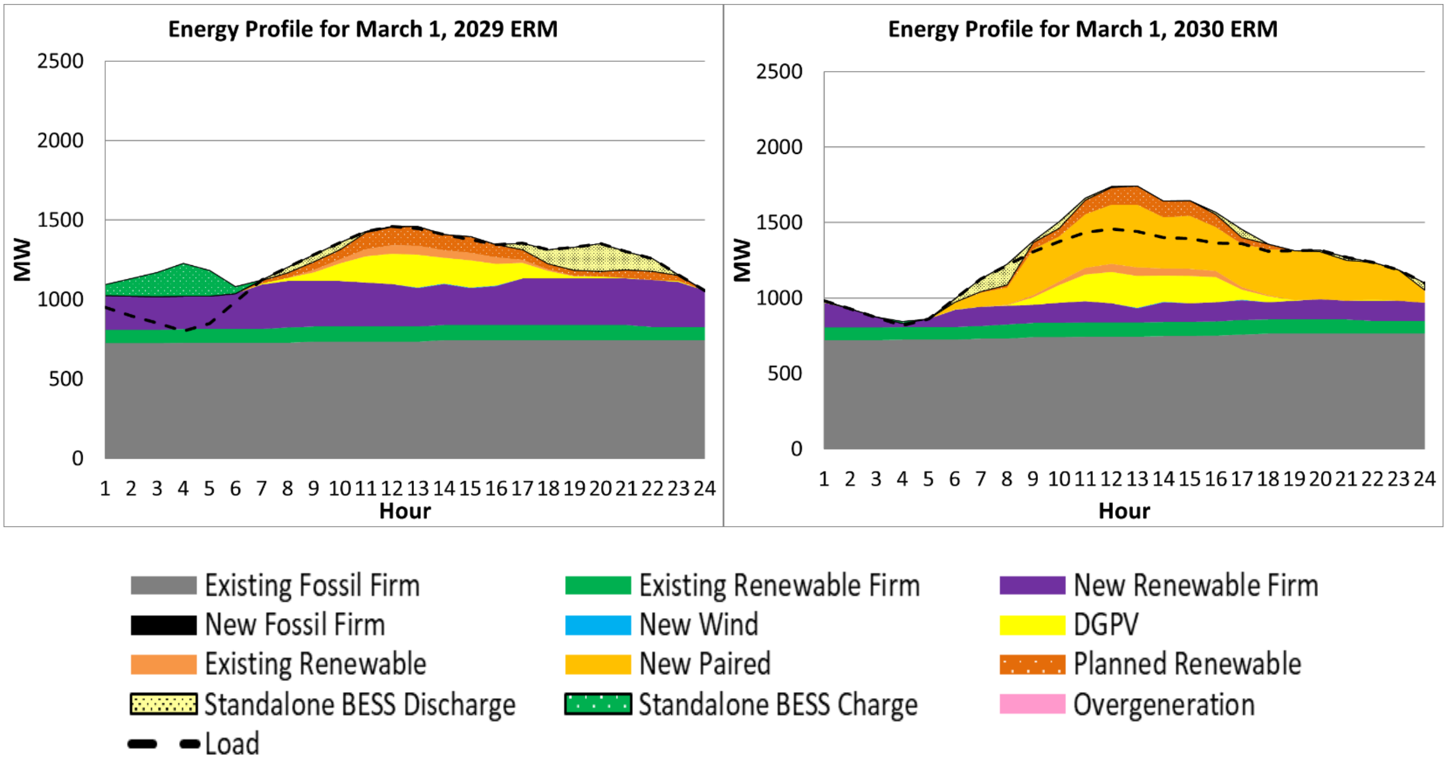


Figure 52. Daily chart – ERM simulation – Base_508 scenario – Low renewable day



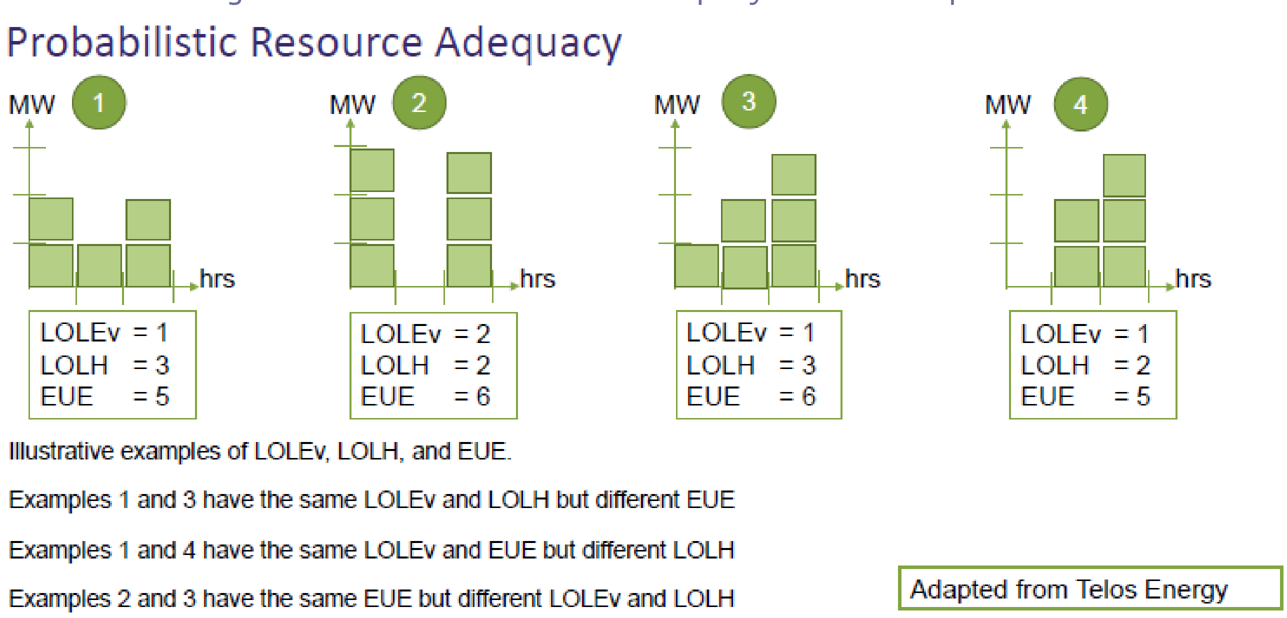
6.5 Probabilistic Resource Adequacy Analysis

This section provides extensive probabilistic resource adequacy analysis (as endorsed by the TAP) to validate the reliability of the resource portfolios generated by RESOLVE in Section 6.3.2. Numerous sensitivities were modeled to test resource adequacy uncertainty and risks associated with energy storage duration, distributed energy resources/demand response, amount of grid-scale solar that may be built, and acceleration/delay of existing fossil-fuel generation, among others.

The probabilistic analysis identified year 2029 as the target year for future firm renewable generation. The analysis used five weather years and 50 thermal generator outage samples. Specifically, PV reliability was based on five years of NREL data, from 2015 through 2019, which was provided as part of the NREL Resource Potential study. Wind reliability was based on historical measured data from existing wind plants for the same five years. DER used historical monthly capacity factor measurements also from the same five years. Thermal generators had 50 random outage samples with each sample modeled as an independent production simulation. A total of 250 (50 outage samples per year for five weather years) samples were modeled.

Four metrics were reported and used to compare the various cases. Loss of Load Expectation (LOLE) is the number of days per year where there is unserved energy. The unserved energy within the day is quantified as Loss of Load Events (LOLEv) defined as the number of unserved energy events per year. The difference between LOLE and LOLEv is that multiple unserved energy events can occur in a single day. Loss of Load Hours (LOLH) is the number of hours of unserved energy. One unserved energy event can last for one or more hours, and therefore, an LOLE of 0.1 days/year is not necessarily the same result as an LOLH of 2.4 hours/year. Expected Unserved Energy (EUE) is the amount of unserved energy. Examples of the various metrics and their interrelationship were shared in the Stakeholder Technical Working Group meeting on June 9, 2022 and recapped below in Figure 53. As shown, while the day has unserved energy, the magnitude, duration, and frequency of that unserved energy affects the various metrics.

Figure 53. Probabilistic resource adequacy metrics examples



The typical North America guideline for LOLE is 0.1 days per year. Belgium, France, Great Britain, and Poland have an LOLH standard of a maximum of 3 hr/yr. AEMO has a reliability standard of a maximum expected unserved energy of 0.002% of total energy demand, which would equate to a target maximum expected unserved energy of 0.137 GWh using Oʻahu's 2029 forecasted energy demand.

This range in LOLE (≤0.1), LOLH (≤3hrs), and EUE (≤0.137 GWh) provides a useful frame of reference when evaluating resource plans that consider different additions of variable renewables and thermal resources. Stricter reliability thresholds may be warranted to address generation resilience on isolated island grids as high impact, low frequency events increase in frequency.

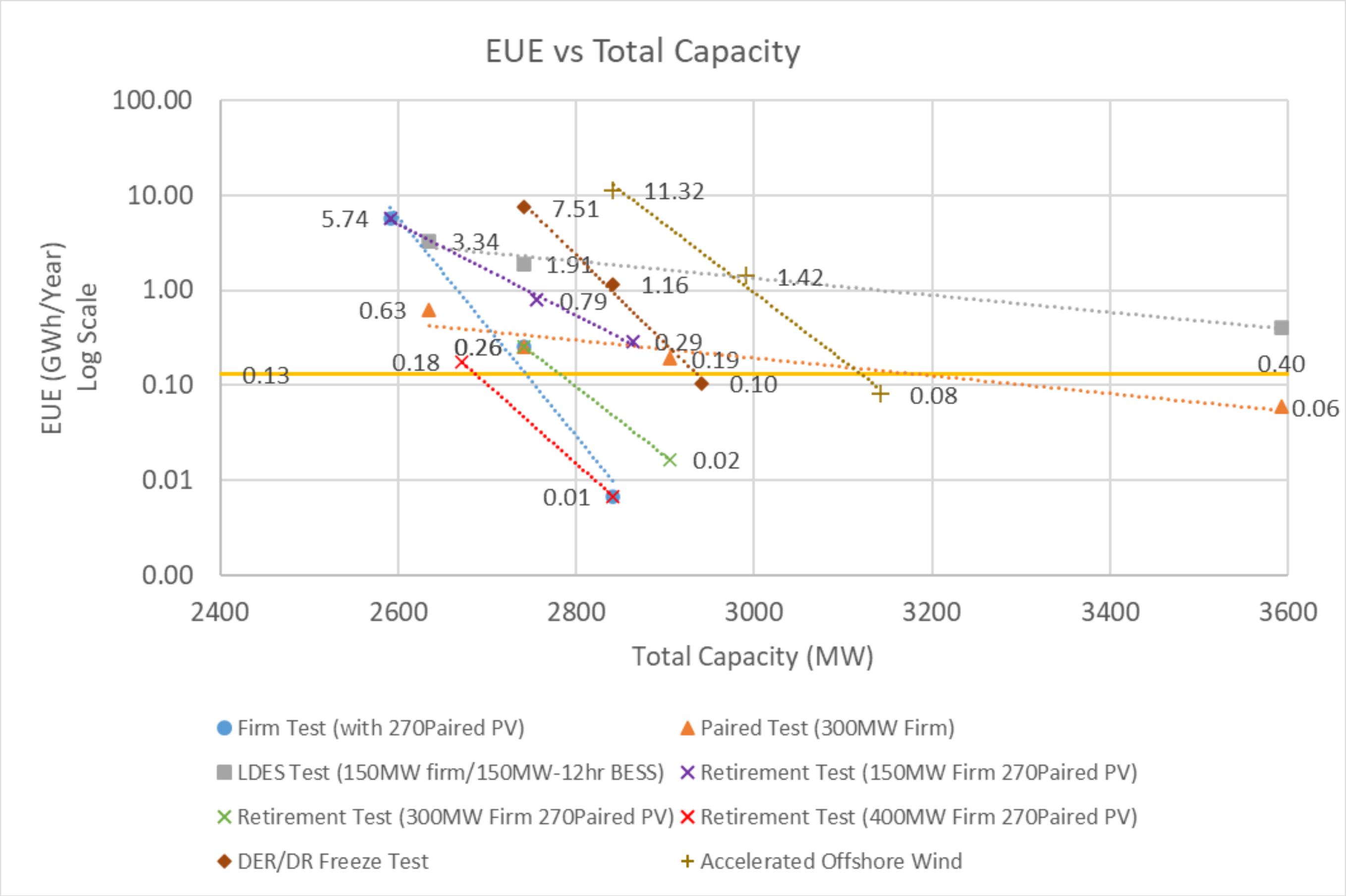
A probabilistic analysis was performed on the following cases and presented to the TAP through the resource adequacy subgroup for feedback.

- Recent Outage Rates Trend Analysis: These cases use the same resource plans from the above cases but update the outage rates for the existing thermal generators to the latest outage forecast based on the most recent trends. These higher outage rates are reflected in the *March 2022 Inputs and Assumptions*. The cases without the higher outage rates used the *August 2021 Inputs and Assumptions* which were based on a longer run historical outage rate for each unit. This analysis will show the impact that the deteriorating performance of the existing generators has on the probabilistic metrics. Based on feedback from the TAP, all subsequent analysis listed below assume the recent, higher outage rates.
- Firm Generation Sensitivity: These cases start with the Base case with 270 MW of paired PV and 0 MW of land-based wind and adjust the amount of firm generation installed. 270 MW paired PV was chosen since it is the approximate size of the Stage 3 RFP target and the size of the Land Constrained scenario. This analysis shows the impact that the size of the new firm generation has on the probabilistic metrics.
- Firm Capacity Based on Paired Renewable: These cases start with the Base case with different amounts of paired renewables and estimate how much firm generation is needed for the EUE to meet the reliability target based on a curve fit of the results.
- Long-Duration Energy Storage: These cases compare runs with 300 MW of new firm generation with cases that have 150 MW of new firm generation and 150 MW of new 12-hour energy storage. This will show the impact that substituting firm generation with long-duration energy storage has on the probabilistic metrics.
- Deactivation Sensitivity: These cases take the Base case with 270 MW of paired PV and add either 150 MW, 300 MW, or 400 MW of new firm generation to look at how the reliability metrics may be affected by the removal from service schedule.
- Load Sensitivity: These cases look at how the reliability metrics are affected by the load forecast and amount of new firm generation, as well as, how the removal from service schedule may need to be adjusted to ensure a reliable system.
- DER/DR Freeze Sensitivity: These cases froze the DER forecast at the end of 2020, EE forecast at the end of 2021, and assumed all EV charging was unmanaged. This analysis shows how the forecast for these customer resources affect the new firm generation needed.
- Additional DER/DR Resource: These cases examine the impact of adding additional 2-hour energy storage on the reliability metrics.

- Accelerated Offshore Wind: These cases look at the impact of adding 400 MW of offshore wind on the reliability metrics and whether adding offshore wind impacts the new firm generation target.
- Planning for Extreme Events: These cases study the impact that a forced outage of 438 consecutive hours on various resource types has on the probabilistic metrics to show whether firm generation provides the same value as variable generation during long duration outages.

Shown below in Figure 55 is a summary of most runs that employed the Base forecast. As shown, the slope of the blue line is steeper than the slope to the orange line indicating that increasing firm generation has greater effect on lowering EUE than increasing paired PV. The figure also shows most cases that meet the EUE reliability target have at least 300MW of firm generation along with additional capacity from another resource.

Figure 54. EUE versus total capacity for various probabilistic analysis using the Base forecast



Shown below in Figure 55 is a summary of all the base cases run which met all three-reliability metrics used in other jurisdictions (i.e., LOLE ≤ 0.1, LOLH ≤ 3hrs, and EUE ≤ 0.137 GWh). In addition, cases which were within twice the reliability metrics on all three (i.e., LOLE ≤ 0.2, LOLH ≤ 6hrs, and EUE ≤ 0.274 GWh) are also shown.

Figure 55. Summary of cases where LOLE, LOLH, and EUE are all within twice the reliability targets of other jurisdictions

Year 2029	Existing Firm (MW)	New Firm (MW)	New Paired PV (MW)	New Onshore Wind (MW)	New Offshore Wind (MW)	LOLE (Days / Yr)	LOLEv (Event / Yr)	LOLH (Hours / Yr)	EUE (GWH / Yr)	Relative Cost ($000)
Base_300_270PVB_0Wd_170HE_Mar22Out	1,135	300	270	0	0	0.09	0.16	0.22	0.02	1,593,167
Base_400_270PVB_0Wnd_Mar22Out	970	400	270	0	0	0.04	0.05	0.09	0.01	1,743,273
Base_300_958PVB_Mar22Out	970	300	958	163	0	0.08	0.20	0.37	0.06	1,419,308
Base_200_1600PVB_Mar22Out	970	200	1,600	163	0	0.08	0.18	0.34	0.09	1,421,125
Base_300_1600PVB_Mar22Out	970	300	1,600	163	0	0.01	0.04	0.07	0.02	1,441,373
Base_250_958PVB_Mar22Out	970	250	958	163	0	0.18	0.42	0.87	0.16	1,412,985
Base_300_270PVB_400OSW_Mar22Out	970	300	270	0	400	0.18	0.34	0.74	0.08	1,335,359

As shown above in Figure 55, a majority of cases require at least 300 MW of firm generation to meet or come close to meeting all three reliability metrics. While there are some cases which require less than 300 MW of new firm generation, those cases require a substantial amount of paired renewables to meet the reliability metrics. To put into context, the Stage 1 and 2 projects that are currently remaining have an aggregate capacity of around 230 MW. Adding 250 MW of new firm generation, would require approximately 958 MW of additional paired PV, or about four times the capacity that's currently expected from Stage 1 and 2. Adding 200 MW of new firm generation (or alternatively 300 MW with accelerated fossil-fuel deactivations), would require approximately 1,600 MW of additional paired PV, or almost seven times the capacity that's currently expected from Stage 1 and 2. A balance must be struck between the need to address the existing firm generation fleet and the time to work with communities, land owners, and developers to realize higher amounts of solar.

Also shown in Figure 55 is the estimated cost in 2029 stated as revenue requirements. This cost includes revenue requirements for fuel, variable and fixed O&M, capacity and energy payments for IPP, and capital. This provides directional costs in a year where both new renewable firm and variable generation are added, taking into account the operating costs with a full year of the simulated resource portfolio. There are five resource portfolios tested that have a cost at or below approximately $1.4B, and more than half of those cases had 300 MW of new firm generation. While there is one portfolio which has 1,600 MW of solar, 163 MW of onshore wind, and only 200 MW of new renewable firm generation, as stated earlier, given the significant amount of hybrid solar needed by 2029, it would be prudent to procure at least 300 MW. If at some point in the future the system conditions allow for additional retirement of fossil-fuel generation, Hawaiian Electric may consider such options to reduce costs.

Shown above in Figure 55, Base_300_270PVB_0Wd_170HE_Mar22Out, achieves an LOLE of 0.09, which is close to the US Mainland standard. Using this case, shown below in Figure 56 is the sum of unserved energy based on the month and hour. As shown, most of the unserved energy is concentrated in the months of April and May during the early morning and evening hours. Whether new resources can further improve reliability will depend in part on their availability during these months and hours.

Figure 56. Unserved energy for 250-sample mean

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.00	0.00	0.00	0.45	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	1.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.00	0.17	0.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	2.96	0.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	1.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	4.43	0.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	3.41	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00

In response to TAP feedback, for a given set of renewable additions, firm generation was incremented to create a relationship between new firm generation additions and EUE. Using this relationship, based on the amount of renewable addition, the amount of new firm generation needed to meet the 0.002% EUE threshold could be estimated.

The following variable renewable additions were considered:

- 270 MW PV (Land constrained limit for new grid-scale PV development, land-based wind not available)
- 958 MW PV (15% slope limit for new grid-scale PV development) and 163 MW onshore wind (remaining NREL technical potential)

- 1,600 MW (New paired PV selected by RESOLVE in the Base case in year 2030) and 163 MW onshore wind (remaining NREL technical potential)

Figure 57. Expected firm thermal addition needed to satisfy EUE reliability target

Year 2029	Existing Firm (MW)	New Firm (MW)	New Paired PV (MW)	New Onshore Wind (MW)	New Offshore Wind (MW)	LOLE (Days / Yr)	LOLEv (Event / Yr)	LOLH (Hours / Yr)	EUE (GWH / Yr)
Curve Fit – 270PVB	970	300	270	0	0	N/A	N/A	N/A	0.137
Curve Fit – 958PVB	970	255	958	163	0	N/A	N/A	N/A	0.137
Curve Fit – 1600PVB	970	175	1,600	163	0	N/A	N/A	N/A	0.137

Applying a curve fit to these cases and targeting 0.002% EUE or 137 MWh yielded a range of new firm thermal capacity from 175 – 300 MW. The EUE reliability standard was applied here based on feedback from the TAP that EUE should be given serious consideration given the high penetration of energy limited and weather dependent resources on the system. Based on the probabilistic analyses conducted herein, LOLE appears to be the most stringent standard to meet so curve fitting to an LOLE of 0.1 day/year instead would likely yield a higher firm capacity addition.

Above 270 MW of PV, further onshore development may be limited based on stakeholder feedback on available potential, and if greater capacities can be developed, REZ infrastructure will be required. To ensure near-term reliability needs can continue to be met, a minimum of 300 MW of firm generation may be needed.

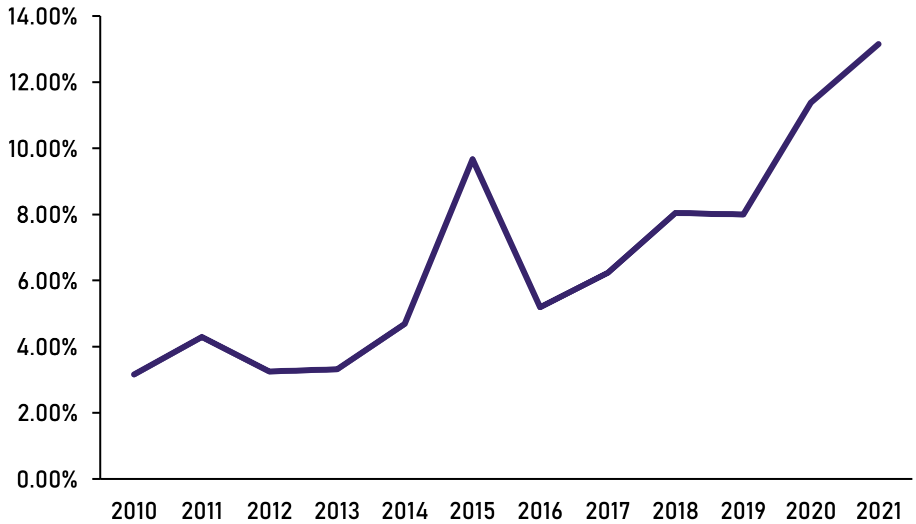
As demonstrated by the Base case simulated in the RESOLVE capacity expansion optimization, low cost renewable dispatchable generation should be the first option. The Stage 3 procurement is based on the 2027 renewable energy optimized by RESOLVE and the limits which the existing transmission system can accommodate. A forthcoming procurement as part of the IGP process will include resources that may take longer to develop through collaboration with communities and project partners. These efforts will work towards increasing low-cost renewables on the system in future years. The 300 MW of new renewable firm generation by 2029 with continued pursuit of low-cost renewable energy is the least-regrets path forward to reduce risks associated with worsening trend of fossil-fuel generator reliability, development of low-cost renewable projects, and the lead time to build renewable firm generation. In the event system conditions allow for additional removal of fossil-fuel generation (i.e., future years where 300 MW of new firm generation is added along with upwards of 1,600 MW of hybrid solar), Hawaiian Electric may further consider accelerated retirements of other fossil-fuel generators.

Additional details on the probabilistic analysis can be found in the following sections. The remaining part of this section disucsses the in-depth analysis performed to support the conlcusions and summary discussed above.

6.5.1 Recent Outage Trend in Current Firm Generation

The historical weighted equivalent forced outage rate for the generating fleet is reported annually as part of the Key Performance Metrics, and it has increased over the past decade, as shown in Figure 58.

Figure 58. Weighted forced outage rate of Hawaiian Electric generators, 2010-2021



An analysis was performed which looked at the impact of higher outage rates on the probabilistic metrics. The outage rates were recently updated to reflect latest trends and were provided in the PUC approved *March 31, 2022 Integrated Grid Planning Inputs and Assumptions*. Shown below in Figure 59 is a comparison of the 2029 outage rates assumed in the initial set of runs, which was provided in August 2021.

Figure 59. Maintenance outage rates and forced outage rates provided in August 2021 and March 2022 Inputs and Assumptions filings

	Maintenance Outage Rate (%)		Forced Outage Rate (%)	
Generator	August 2021	March 2022	August 2021	March 2022
Waiau 5	1.9	11.5	5.0	15.0
Waiau 6	1.9	11.5	5.0	15.0
Waiau 7	13.4	32.0	4.5	13.0
Waiau 8	21.1	11.5	4.5	13.0
Waiau 9	3.8	3.8	4.0	4.0
Waiau 10	3.8	3.8	4.0	4.0
Kahe 1	3.8	11.5	4.5	13.0
Kahe 2	3.8	11.5	4.5	13.0
Kahe 3	13.4	11.5	4.5	13.0
Kahe 4	3.8	11.5	4.5	13.0
Kahe 5	1.9	11.5	5.0	10.0
Kahe 6	13.4	11.5	5.0	10.0
CIP CT-1	3.8	3.8	3.0	4.0
H-POWER	0.0	0.0	3.0	3.0
Airport DSG	1.9	1.9	5.0	5.0
Schofield	1.9	1.9	2.0	2.0

The following scenarios modeled the updated outage rates to match the March 2022, *IGP Inputs and Assumptions* filing.

- Base_508_Staggered_Mar22Out
- Base_688_Staggered_Mar22Out
- Base_Accel_Mar22Out
- Base_Accel_508_Staggered_Mar22Out
- LC_508_Staggered_Mar22Out
- LC_688_Staggered_Mar22Out
- LC_Accel_Mar22Out
- LC_Accel_508_Staggered_Mar22Out

Shown below in Figure 60 is the capacity of resources in 2029 for the Base cases. The capacity of resources in 2029 for the Land Constrained cases is shown in Figure 61.

Figure 60. Probabilistic analysis - resource capacity summary, year 2029. Recent outage trend sensitivity, Base cases

Year 2029	Existing	Base_508_ Staggered	Base_688_ Staggered	Base_Accel	Base_Accel_ 508_Staggered
Existing Firm	1,729	970	970	970	970
Existing PV	188	188	188	188	188
Existing Wind	123	123	123	123	123
CBRE	0	185	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94	94
Future PV	0	0	0	1,577	1,577
Future Wind	0	163	163	163	163
Future Firm Units	0	300 MW (6-50 MW CT)	480 MW (6-50 MW CT 9-20 MW Biomass)	0	300 MW (6-50 MW CT)
Total	**2,040**	**2,163**	**2,343**	**3,440**	**3,740**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	287 MW / 539 MWh	287 MW / 539 MWh	1,956 MW / 5,174 MWh	1,956 MW / 5,174 MWh
Total	**0 MW / 0 MWh**	**705 MW / 2,165 MWh**	**705 MW / 2,165 MWh**	**2,374 MW / 6,800 MWh**	**2,374 MW / 6,800 MWh**

Figure 61. Probabilistic analysis - resource capacity summary, year 2029. Recent outage trend sensitivity, Land Constrained cases

Year 2029	Existing	LC_508_Staggered	LC_688_Staggered	LC_Accel	LC_Accel_508_Staggered
Existing Firm	1,729	970	970	970	970
Existing PV	188	188	188	188	188
Existing Wind	123	123	123	123	123
CBRE	0	185	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West Oʻahu	0	139.5	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94	94
Future PV	0	0	0	270	270
Future Wind	0	0	0	0	0
Future Firm Units	0	300 MW (6-50 MW CT)	480 MW (6-50 MW CT 9-20 MW Biomass)	0	300 MW (6-50 MW CT)
Total	**2,040**	**2,000**	**2,180**	**1,970**	**2,270**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	232.5 MW / 437 MWh	232.5 MW / 437 MWh	584 MW / 857 MWh	584 MW / 857 MWh
Total	**0 MW /** 0 MWh	**651 MW / 2,063 MWh**	**651 MW / 2,063 MWh**	**1,002** MW / 2,483 MWh	**1,002** MW / 2,483 MWh

Shown below in Figure 62 and Figure 63 are the impact that the higher outage rates have on the reliability metrics discussed earlier (noted by '_Mar22Out') compared to the previous outgae rates used in the August 2021 Inputs and Assumptions. The higher outage rates result in unserved energy, even in the cases where 500 MW of new firm generation is added or the 2030 renewables are accelerated to 2029. Increasing renewables on the system will likely increase the stress on the existing thermal generators and cause higher outage rates in the future.

Figure 62. Probabilistic analysis results summary, year 2029. Recent outage trend sensitivity, Base cases

	New Firm Generation (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	1.18	1.30	2.90	0.13
Base_508_Staggered	300	0.22	0.38	0.86	0.07
Base_688_Staggered	480	0.00	0.00	0.00	0.00
Base_508_Staggered_ Mar22Out	300	1.30	2.19	5.98	0.63
Base_688_Staggered_ Mar22Out	480	0.04	0.06	0.17	0.02
Base_Accel	0	0.52	1.05	2.01	0.44
Base_Accel_508_Staggered	300	0.00	0.00	0.00	0.00
Base_Accel_Mar22Out	0	2.08	4.36	8.40	2.03
Base_Accel_508_Staggered _Mar22Out	300	0.03	0.07	0.10	0.02

Figure 63. Probabilistic analysis results summary, year 2029. Recent outage trend sensitivity, Land Constrained cases

Year 2029	New Firm Generation (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	1.18	1.30	2.90	0.13
LC_508_Staggered	300	0.30	0.49	1.11	0.09
LC_688_Staggered	480	0.00	0.00	0.00	0.00
LC_508_Staggered_ Mar22Out	300	2.36	4.05	11.14	1.16
LC_688_Staggered_ Mar22Out	480	0.03	0.05	0.08	0.00
LC_Accel	0	29.55	56.92	159.10	22.16
LC_Accel_508_Staggered	300	0.14	0.28	0.48	0.04
LC_Accel_Mar22Out	0	72.82	146.28	460.36	69.81
LC_Accel_508_Staggered _Mar22Out	300	1.32	2.38	5.35	0.56

The results of higher outage rate sensitivities highlight the reliability risk of continuing to run the existing fossil-fuel generation and failing to procure replacement resources. In a Land Constrained future, more than 300 MW of firm renewable energy will be needed to attain a LOLE within the target range.

6.5.2 Firm Generation Sensitivity

Using the latest outage rates, the TAP was interested to see how the metrics are affected by the size of the new firm generation. Therefore, the following scenarios were tested.

- Base_150_270PVB_0Wnd_Mar22Out
  - Base case with 3-50MW CT generators added in 2029, 270 MW PV+ BESS, and 0 MW onshore wind.
  - 270 MW paired PV is the approximate size of the Stage 3 RFP target and limit on the Land Constrained case. The paired BESS was assumed to have 3-hour duration, which is the same size as the paired BESS chosen by RESOLVE as the optimal amount. Land-based or onshore wind was removed due to land use and community acceptance concerns.
- Base_300_270PVB_0Wnd_Mar22Out
  - Base_150_270PVB_0Wnd_Mar22Out with 6-50MW CT generators added in 2029 instead of 3-50MW CT generators.
- Base_400_270PVB_0Wnd_Mar22Out
  - Base_150_270PVB_0Wnd_Mar22Out with 8-50MW CT generators added in 2029 instead of 3-50MW CT generators.

Shown below in Figure 64 is the capacity of resources in 2029 for these cases.

Figure 64. Probabilistic analysis - resource capacity summary, year 2029. New Firm Generation sensitivity

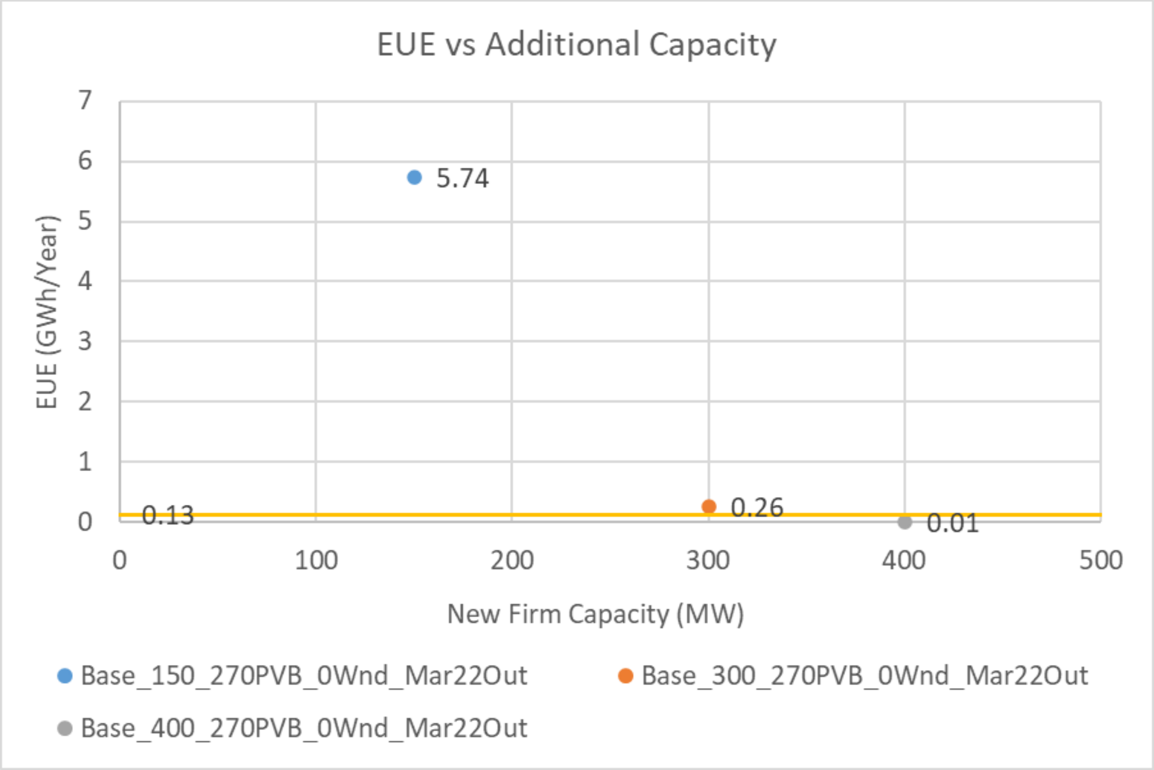
Year 2029	Existing	Base_150_270PVB_0Wnd_ Mar22Out	Base_300_270PVB_0Wnd_ Mar22Out	Base_400_270PVB_0Wnd_ Mar22Out
Existing Firm	1,729	970	970	970
Existing PV	188	188	188	188
Existing Wind	123	123	123	123
CBRE	0	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94
Future PV	0	270	270	270
Future Wind	0	0	0	0
Future Firm Units	0	150 MW (3-50 MW CT)	300 MW (6-50 MW CT)	400 MW (8-50 MW CT)
Total	**2,040**	2,120	2,270	2,370
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh
Total	**0 MW / 0 MWh**	975 MW / 2,975 MWh	975 MW / 2,975 MWh	975 MW / 2,975 MWh

Shown below in Figure 65 is the impact that the new firm generation capacity has on the various reliability metrics discussed earlier. Shown in Figure 66 is the relationship between the new firm generation capacity and EUE. As expected, as the size of the new firm generation increases, the reliability metrics improves. The results also show that with the latest outage rates, 300MW of new firm generation will not be adequate to meet the reliability targets; at least 400 MW of new firm generation will be needed. As the existing firm generation gets older and is operated under more extreme conditions, it is likely that the outage rates will increase further, making the need for at least 400MW of firm generation more likely.

Figure 65. Probabilistic analysis - results summary, year 2029. New Firm Generation sensitivity

Year 2029	New Firm Generation (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	1.18	1.30	2.90	0.13
Base_150_270PVB_0Wnd_Mar22Out	150	9.25	17.75	42.42	5.74
Base_300_270PVB_0Wnd_Mar22Out	300	0.66	1.18	2.47	0.26
Base_400_270PVB_0Wnd_Mar22Out	400	0.04	0.05	0.09	0.01

Figure 66. EUE and additional firm capacity, year 2029. New Firm Generation sensitivity



6.5.3 Firm Capacity Based on Paired Renewable Size

Using the latest outage rates, the TAP was interested to see how much firm generation would be needed to achieve the reliability target based on a certain amount of paired renewables that was added. For example, if 270 MW of paired PV was added, how much firm generation would be needed to make the system reliable. Therefore, the following scenarios were tested.

- Base_150_270PVB_0Wnd_Mar22Out
  - Base case with 3-50MW CT generators added in 2029, 270 MW PV+ BESS, and 0MW onshore wind.
  - 270 MW paired PV is the approximate size of the Stage 3 RFP target. The paired BESS was assumed to have 3-hour duration, which is the same size as the paired BESS chosen by RESOLVE as the optimal amount. Onshore wind was removed due to land use and community acceptance concerns.
- Base_300_270PVB_0Wnd_Mar22Out
  - Base_150_270PVB_0Wnd_Mar22Out with 6-50MW CT generators added in 2029 instead of 3-50MW CT generators.
- Base_400_270PVB_0Wnd_Mar22Out
  - Base_150_270PVB_0Wnd_Mar22Out with 8-50MW CT generators added in 2029 instead of 3-50MW CT generators.
- Base_150_958PVB_Mar22Out
  - Base case with 3-50MW CT generators added in 2029 and 958MW PV+BESS. The 958MW PV+BESS is the NREL resource potential on slopes up to 15%. Includes 163 MW of onshore wind.
- Base_250_958PVB_Mar22Out
  - Base_150_958PVB_Mar22Out with 5-50MW CT generators added in 2029 instead of 3-50MW CT generators.
- Base_300_958PVB_Mar22Out
  - Base_150_958PVB_Mar22Out with 6-50MW CT generators added in 2029 instead of 3-50MW CT generators.
- Base_150_1600PVB_Mar22Out
  - Base case with 3-50MW CT generators added in 2029 and 1600MW PV+BESS. The 1600MW PV+BESS is approximately the amount that was added by RESOLVE in 2030. Includes 163 MW of onshore wind.
- Base_200_1600PVB _Mar22Out
  - Base_150_1600PVB_Mar22Out with 4-50MW CT generators added in 2029 instead of 3-50MW CT generators.
- Base_300_1600PVB _Mar22Out
  - Base_150_1600PVB_Mar22Out with 6-50MW CT generators added in 2029 instead of 3-50MW CT generators.

In all scenarios, the paired PV+BESS system was assumed to have a 3-hour duration. This is the same duration, rounded to the nearest hour, of the paired battery that was chosen by RESOLVE as the optimal amount. Shown below in Figure 67, Figure 68, and Figure 69 is the capacity of resources in 2029 for the case with 270 MW paired PV, 958 MW paired PV, and 1600 MW paired PV, respectively.

Figure 67. Probabilistic analysis - resource capacity summary, year 2029. Firm Capacity cases with 270 MW paired renewables

Year 2029	Existing	Base_150_270PVB_0Wnd_Mar22Out	Base_300_270PVB_0Wnd_Mar22Out	Base_400_270PVB_0Wnd_Mar22Out
Existing Firm	1,729	970	970	970
Existing PV	188	188	188	188
Existing Wind	123	123	123	123
CBRE	0	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94
Future PV	0	270	270	270
Future Wind	0	0	0	0
Future Firm Units	0	150 MW (3-50 MW CT)	300 MW (6-50 MW CT)	400 MW (8-50 MW CT)
Total	**2,040**	**2,120**	**2,270**	**2,370**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh
Total	**0 MW / 0 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**

Figure 68. Probabilistic analysis - resource capacity summary, year 2029. Firm Capacity cases with 958 MW paired renewables

Year 2029	Existing	Base_150_958PVB_Mar22Out	Base_250_958PVB_Mar22Out	Base_300_958PVB_Mar22Out
Existing Firm	1,729	970	970	970
Existing PV	188	188	188	188
Existing Wind	123	123	123	123
CBRE	0	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94
Future PV	0	958	958	958
Future Wind	0	163	163	163
Future Firm Units	0	150 MW (3-50 MW CT)	250 MW (5-50 MW CT)	300 MW (6-50 MW CT)
Total	**2,040**	**2,971**	**3,121**	**3,121**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	1,245 MW / 3,413 MWh	1,245 MW / 3,413 MWh	1,245 MW / 3,413 MWh
Total	**0 MW / 0 MWh**	**1,663 MW / 5,039 MWh**	**1,663 MW / 5,039 MWh**	**1,663 MW / 5,039 MWh**

Figure 69. Probabilistic analysis - resource capacity summary, year 2029. Firm Capacity cases with 1600 MW paired renewables

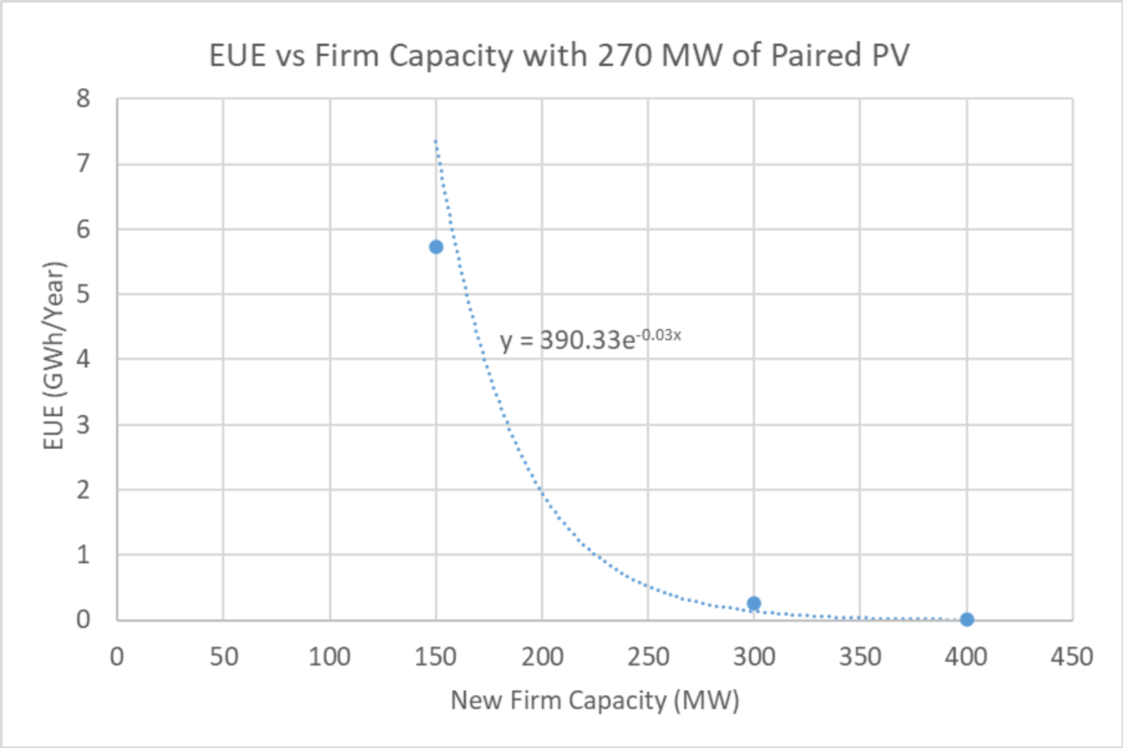
Year 2029	Existing	Base_150_1600PVB_Mar22Out	Base_200_1600PVB_Mar22Out	Base_300_1600PVB_Mar22Out
Existing Firm	1,729	970	970	970
Existing PV	188	188	188	188
Existing Wind	123	123	123	123
CBRE	0	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O‘ahu	0	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94
Future PV	0	1600	1600	1600
Future Wind	0	163	163	163
Future Firm Units	0	150 MW (3-50 MW CT)	200 MW (4-50 MW CT)	300 MW (6-50 MW CT)
Total	**2,040**	**3,613**	**3,663**	**3,763**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	1,887 MW / 5,339 MWh	1,887 MW / 5,339 MWh	1,887 MW / 5,339 MWh
Total	**0 MW / 0 MWh**	**2,305 MW / 6,965 MWh**	**2,305 MW / 6,965 MWh**	**2,305 MW / 6,965 MWh**

Shown below in Figure 70 and Figure 71 is the relationship between the reliability metrics and the new firm capacity in 2029 for the Base case with 270 MW of paired PV and recent outage rates. The trendline produced by the probabilistic results shown in Figure 71 suggest that with 270 MW of paired PV, the EUE reliability target of 0.137 GWh/year can be achieve with approximately 300 MW of new firm generation. Because the curve fit does not directly intersect the cases that were explicitly modeled, it may slightly understate the firm capacity need as shown here when comparing the 300 MW based on curve fit against the 300 MW that was modeled and did not meet the EUE target. However, it is directionally consistent when compared to the curve fits at 958 MW and 1,600 MW of paired PV to show trends in firm capacity need.

Figure 70. Probabilistic analysis - results summary, year 2029. Firm Capacity cases with 270 MW paired PV

Year 2029	New Firm (MW)	New Paired PV (MW)	New Onshore Wind (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	0	0	1.18	1.30	2.90	0.13
Base_150_ 270PVB_0Wnd_Mar22Out	150	270	0	9.25	17.75	42.42	5.74
Base_300_ 270PVB_0Wnd_Mar22Out	300	270	0	0.66	1.18	2.47	0.26
Base_400_ 270PVB_0Wnd_Mar22Out	400	270	0	0.04	0.05	0.09	0.01

Figure 71. EUE and new firm capacity in 2029. Firm Capacity cases with 270 MW paired PV

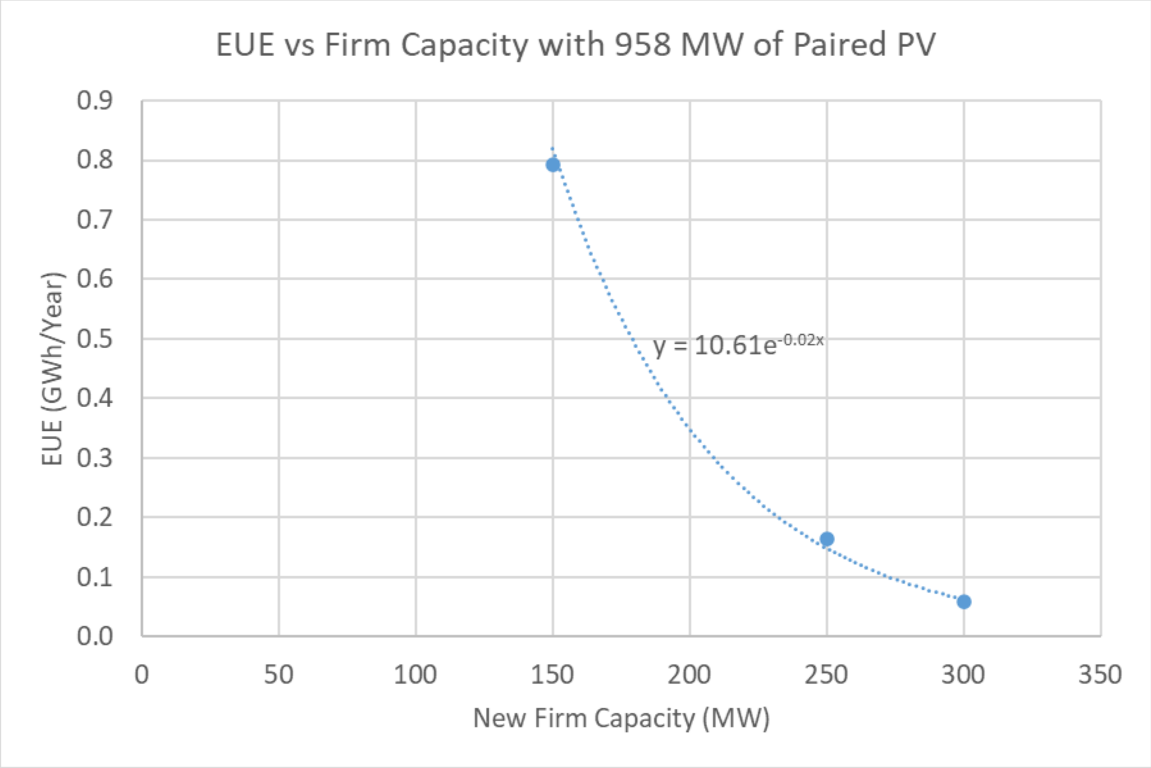


Shown below in Figure 72 and Figure 73 is the relationship between the reliability metrics and the new firm capacity in 2029 for the Base case with 958 MW of paired PV and recent outage rates. The trendline produced by the probabilistic results shown in Figure 73 suggest that with 958 MW of paired PV, the EUE reliability target of 0.137 GWh/year can be achieved with approximately 255 MW of new firm generation.

Figure 72. Probabilistic analysis - results summary, year 2029. Firm Capacity cases with 958 MW Paired PV

Year 2029	New Firm (MW)	New Paired PV (MW)	New Onshore Wind (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	0	0	1.18	1.30	2.90	0.13
Base_150_958PVB_Mar22Out	150	958	163	0.98	1.98	4.12	0.79
Base_250_958PVB_Mar22Out	250	958	163	0.18	0.42	0.87	0.16
Base_300_958PVB_Mar22Out	300	958	163	0.08	0.20	0.37	0.06

Figure 73. EUE and new firm capacity in 2029. Firm Capacity cases with 958 MW paired PV

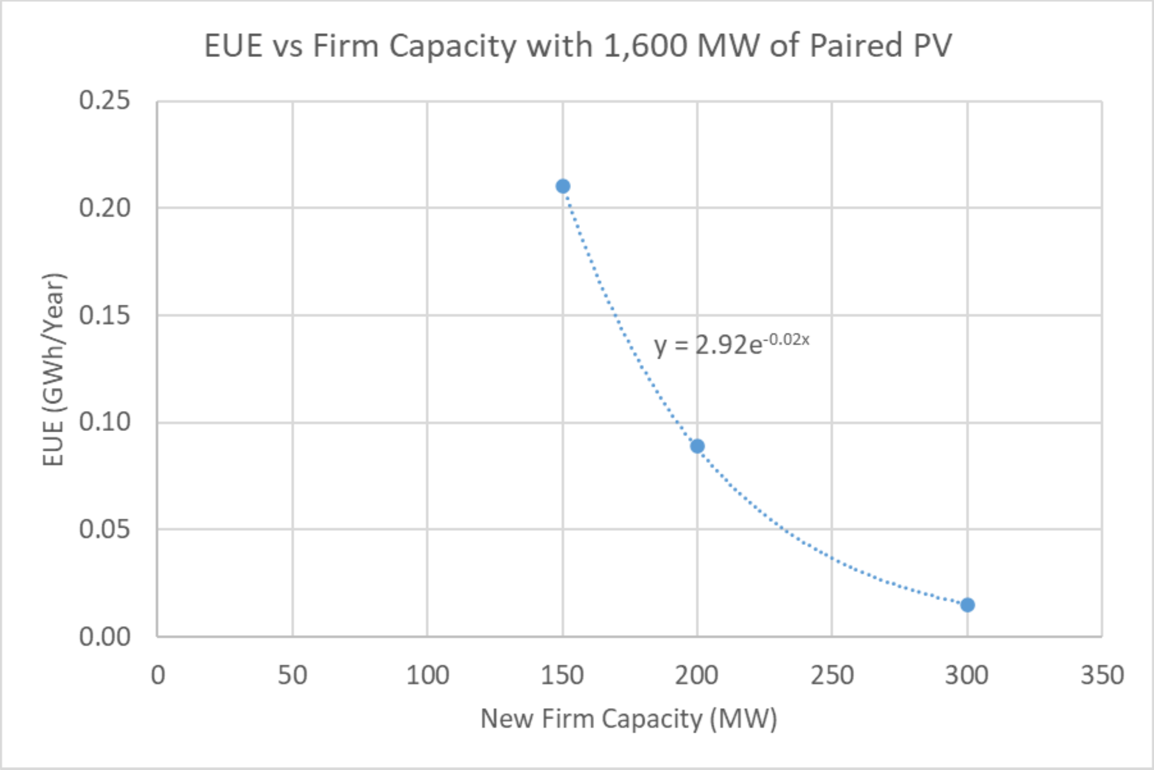


Shown below in Figure 74 and Figure 75 is the relationship between the reliability metrics and the new firm capacity in 2029 for the Base case with 1,600 MW of paired PV and recent outage rates. The trendline produced by the probabilistic results shown in Figure 75 suggest that with 1,600 MW of paired PV, the EUE reliability target of 0.137 GWh/year can be achieve with approximately 175 MW of new firm generation.

Figure 74. Probabilistic analysis - results summary, year 2029. Firm Capacity cases with 1,600 MW paired PV

Year 2029	New Firm (MW)	New Paired PV (MW)	New Onshore Wind (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	0	0	1.18	1.30	2.90	0.13
Base_150_ 1600PVB_ Mar22Out	150	1,600	163	0.22	0.49	0.84	0.21
Base_200_ 1600PVB_ Mar22Out	200	1,600	163	0.08	0.18	0.34	0.09
Base_300_ 1600PVB_ Mar22Out	300	1,600	163	0.01	0.04	0.07	0.02

Figure 75. EUE and new firm capacity in 2029. Firm Capacity cases with 1,600 MW paired PV



6.5.4 Long-Duration Energy Storage

Using the latest outage rates, the TAP was also interested to see how the metrics are affected by the size of the standalone BESS system. Therefore, the following scenarios were tested.

- Base_300_Mar22Out
  - 300MW of firm generation is added to the Base case resource plan. This is the same as the Base_508 Staggered scenario and consist of 6-50MW CT generators.
- Base_150_150MW12hrSaB_Mar22Out
  - Base_300_Mar22Out with 150MW of new firm generation replaced with 150MW-12hr Standalone BESS.
- Base_300_270PVB_0Wd_Mar22Out
  - Base_300_Mar22Out with 270MW PV+BESS system added to the Base resource plan, but without the onshore wind. The 270MW PV+BESS is the approximate size of the Stage 3 RFP. Onshore wind was removed due to land use and community acceptance concerns.
- Base_150_150MW12hrSaB_270PVB_0Wd_Mar22Out
  - Base_300_270PVB_0Wd_Mar22Out with 150MW of new firm generation replaced with 150MW-12hr Standalone BESS.
- Base_300_958PVB_Mar22Out
  - Base_300_Mar22Out with 958MW PV+BESS system added to the Base resource plan. The 958MW PV+BESS is the NREL resource potential on slopes up to 15%.
- Base_150_150MW12hrSaB_958PVB_Mar22Out
  - Base_300_958PVB_Mar22Out with 150MW of new firm generation replaced with 150MW-12hr Standalone BESS.

Shown below in Figure 76 is the capacity of resources in 2029 for these cases.

Figure 76. Probabilistic analysis - resource capacity summary, year 2029. Long-Duration Energy Storage sensitivity

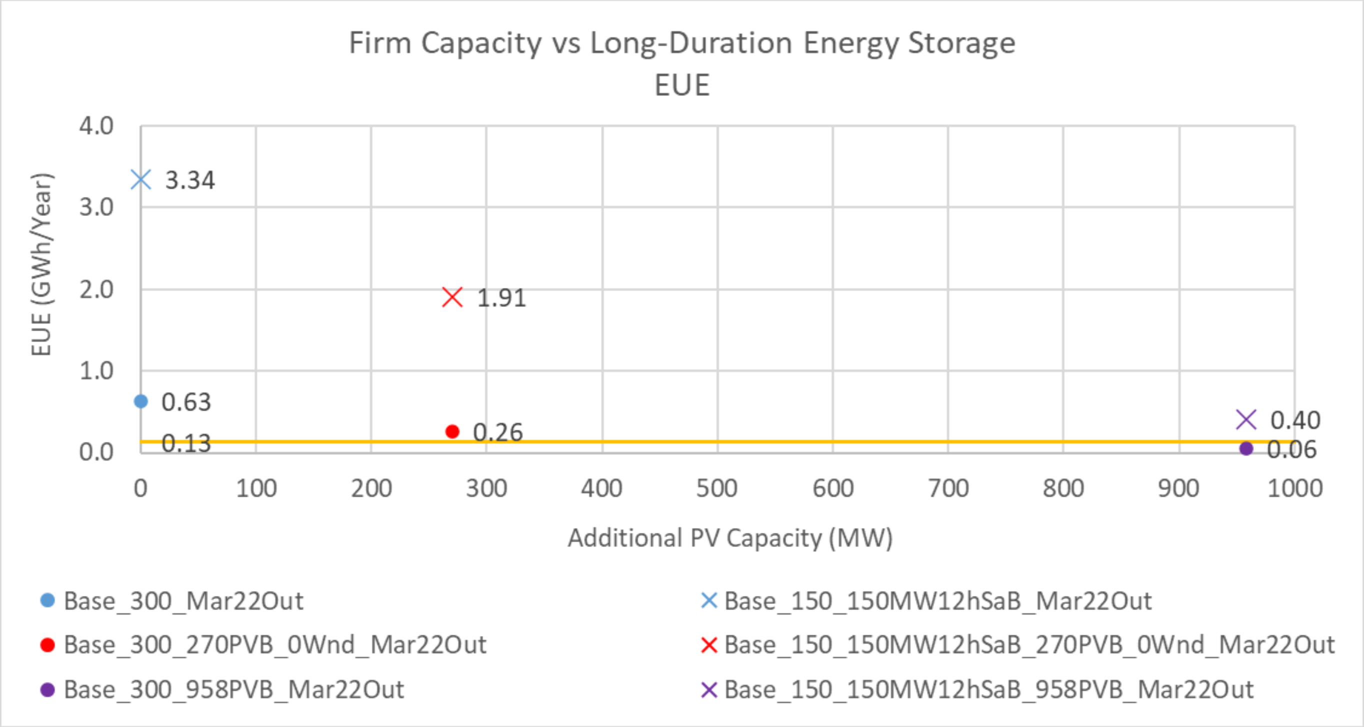
Year 2029	Existing	Base_300_ Mar22Out	Base_150_ 150MW12hrSaB_ Mar22Out	Base_300_ 270PVB_0Wd_ Mar22Out	Base_150_ 150MW12hrSaB_ 270PVB_0Wd_ Mar22Out	Base_300_ 958PVB_ Mar22Out	Base_150_ 150MW12hrSaB_ 958PVB_ Mar22Out
Existing Firm	1,729	970	970	970	970	970	970
Existing PV	188	188	188	188	188	188	188
Existing Wind	123	123	123	123	123	123	123
CBRE	0	185	185	185	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West Oʻahu	0	139.5	139.5	139.5	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94	94	94	94
Future PV	0	0	0	270	270	958	958
Future Wind	0	163	163	0	0	163	163
Future Firm Units	0	300 MW (6-50 MW CT)	150 MW (3-50 MW CT)	300 MW (6-50 MW CT)	150 MW (3-50 MW CT)	300 MW (6-50 MW CT)	150 MW (3-50 MW CT)
Total	**2,040**	**2,163**	**2,013**	**2,270**	**2,120**	**3,121**	**2,971**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	287 MW / 539 MWh	437 MW / 2,339 MWh	557 MW / 1,349 MWh	707 MW / 3,149 MWh	1,245 MW / 3,413 MWh	1,395 MW / 5,213 MWh
Total	**0 MW / 0 MWh**	**705 MW / 2,165 MWh**	**855 MW / 3,965 MWh**	**975 MW / 2,975 MWh**	**1,125 MW / 4,775 MWh**	**1,663 MW / 5,039 MWh**	**1,813 MW / 6,839 MWh**

Shown below in Figure 77 is the impact that a 150MW/12-hour energy storage system has on the various reliability metrics discussed earlier and how it compares to 150MW of firm generation instead. This information is also shown in Figure 78. As shown, in all scenarios, the 150MW new firm generation results in better reliability than a 150 MW/12-hour standalone energy storage system, even with large amounts of renewables on the system.

Figure 77. Probabilistic analysis - results summary, year 2029. Long-Duration Energy Storage sensitivity

Year 2029	New Firm Generation (MW)	New Paired PV (MW)	New Standalone Storage MW/MWh)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	0	0MW / 0MWh	1.18	1.30	2.90	0.13
Base_300_ Mar22Out	300	0	287 MW / 539 MWh	1.30	2.19	5.98	0.63
Base_150_ 150MW12hrSaB_ Mar22Out	150	0	437 MW / 2,339 MWh	4.15	8.91	23.19	3.34
Base_300_270PV B_ 0Wd_Mar22Out	300	270	287 MW / 539 MWh	0.66	1.18	2.47	0.26
Base_150_ 150MW12hrSaB_ 270PVB_0Wd_ Mar22Out	150	270	437 MW / 2,339 MWh	2.48	5.16	12.17	1.91
Base_300_958P VB_ Mar22Out	300	958	287 MW / 539 MWh	0.08	0.20	0.37	0.06
Base_150_ 150MW12hrSaB_ 958PVB_Mar22O ut	150	958	437 MW / 2,339 MWh	0.36	0.84	1.89	0.40

Figure 78. EUE, firm capacity and long-duration storage in 2029. Long-Duration Energy Storage sensitivity



6.5.5 Removal from Service Schedule Sensitivity

Sensitivities on the removal from service schedule were also analyzed to study how the schedule may be adjusted to improve reliability based on the amount of new firm generation.

- Base_150_270PVB_0Wd_Mar22Out
  - 150MW of new firm generation and 270MW PV+BESS system is added to the Base resource plan. The 270MW PV+BESS is the approximate size of the Stage 3 procurement. Onshore or land-based wind was removed due to land use and community acceptance concerns.
- Base_150_270PVB_0Wd_170HE_Mar22Out
  - Base_150_270PVB_0Wd_Mar22Out with the removal of 170MW of utility thermal generation delayed.
- Base_150_270PVB_0Wd_280HE_Mar22Out
  - Base_150_270PVB_0Wd_Mar22Out with the removal of 280MW of utility thermal generation delayed.
- Base_300_270PVB_0Wd_Mar22Out
  - Base_150_270PVB_0Wd_Mar22Out with 300MW of new firm generation instead of 150MW of new firm generation
- Base_300_270PVB_0Wd_170HE_Mar22Out
  - Base_300_270PVB_0Wd_Mar22Out with the removal of 170MW of utility thermal generation delayed.
- Base_400_270PVB_0Wd_Mar22Out
  - Base_150_270PVB_0Wd_Mar22Out with 400MW of new firm generation instead of 150MW of new firm generation.

- Base_400_270PVB_0Wd_wo170HE_Mar22Out
    - Base_400_270PVB_0Wd_Mar22Out with the removal of an additional 170MW of utility firm generation accelerated.

Shown below in Figure 79 is the capacity of resources in 2029 for these cases. Due to rounding, the existing firm capacity may be slightly different from the amount of removed capacity that is accelerated/delayed in the case descriptions above.

Figure 79. Probabilistic analysis – resource capacity summary, year 2029. Removal from Service sensitivity

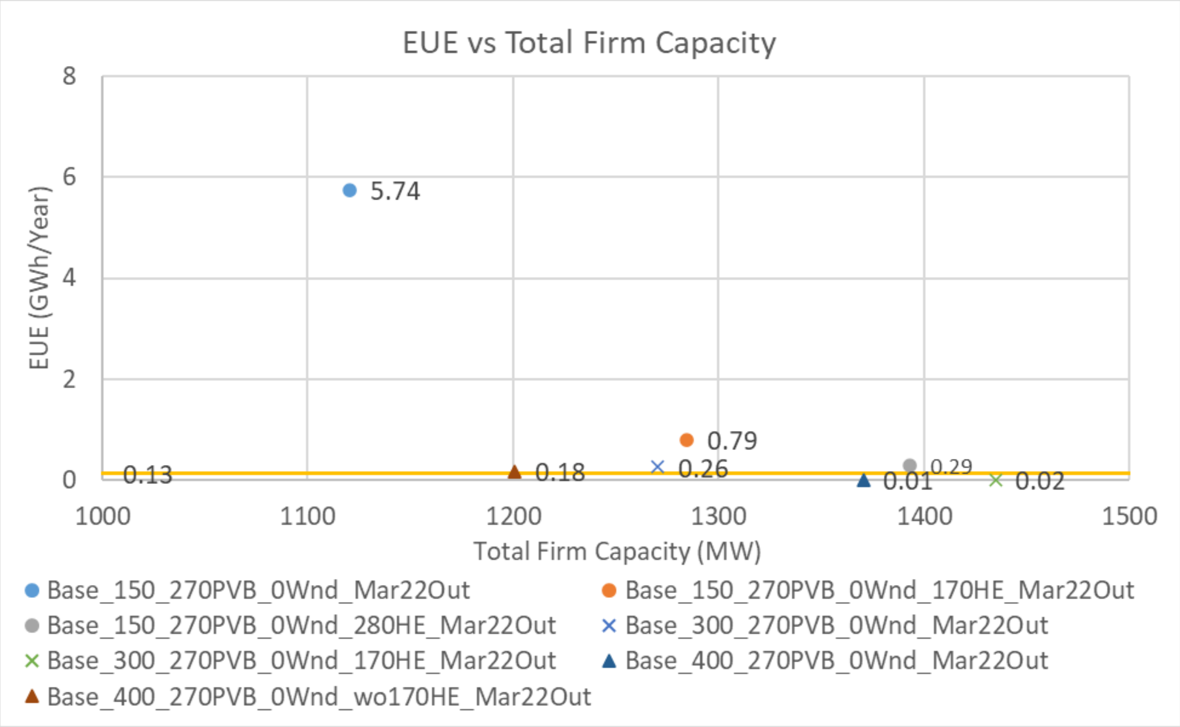
Year 2029	Existing	Base_150_ 270PVB_0Wd_ Mar22Out	Base_150_ 270PVB_0Wd_ 170HE_ Mar22Out	Base_150_ 270PVB_0Wd_ 280HE_ Mar22Out	Base_300_ 270PVB_0Wd_ Mar22Out	Base_300_ 270PVB_0Wd_ 170HE_ Mar22Out	Base_400_ 270PVB_0Wd_ Mar22Out	Base_400_ 270PVB_0Wd_ Mar22Out
Existing Firm	1,729	970	1,135	1,243	970	1,135	970	801
Existing PV	188	188	188	188	188	188	188	188
Existing Wind	123	123	123	123	123	123	123	123
CBRE	0	185	185	185	185	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5	139.5	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94	94	94	94	94
Future PV	0	270	270	270	270	270	270	270
Future Wind	0	0	0	0	0	0	0	0
Future Firm Units	0	150 MW (3-50 MW CT)	150 MW (3-50 MW CT)	150 MW (3-50 MW CT)	300 MW (6-50 MW CT)	300 MW (6-50 MW CT)	400 MW (8-50 MW CT)	400 MW (8-50 MW CT)
Total	**2,040**	**2,120**	**2,284**	**2,393**	**2,270**	**2,434**	**2,370**	**2,201**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh
Total	**0 MW / 0 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**

Shown below in Figure 80 is the impact that the existing and new firm generation capacity has on the various reliability metrics discussed earlier. This information is also shown in Figure 81. As shown below, with 270MW of paired PV+BESS and only 150MW of new firm generation, most of the reliability targets will not be met, even with delaying the removal of 280MW of utility firm generation. This demonstrates the urgency in which the services provided by existing fossil-fuel generation must be replaced to reduce the risk of an aging and less reliable generation fleet. With 270MW of paired PV+BESS and the Base plan removal from service schedule, at least 300MW of new firm generation will be needed to meet the reliability targets.

Figure 80. Probabilistic analysis - results summary, year 2029. Removal from Service sensitivity

Year 2029	Existing Firm Generation (MW)	New Firm Generation (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	1,729	0	1.18	1.30	2.90	0.13
Base_150_270PVB_0Wd_Mar22Out	970	150	9.25	17.75	42.42	5.74
Base_150_270PVB_0Wd_170HE_Mar22Out	1,135	150	1.70	3.20	6.52	0.79
Base_150_270PVB_0Wd_280HE_Mar22Out	1,243	150	0.54	1.02	2.25	0.29
Base_300_270PVB_0Wd_Mar22Out	970	300	0.66	1.18	2.47	0.26
Base_300_270PVB_0Wd_170HE_Mar22Out	1,135	300	0.09	0.16	0.22	0.02
Base_400_270PVB_0Wd_Mar22Out	970	400	0.04	0.05	0.09	0.01
Base_400_270PVB_0Wd_wo170HE_Mar22Out	801	400	0.47	0.92	1.82	0.18

Figure 81. EUE and total firm capacity in 2029. Removal from Service sensitivity



6.5.6 Load Sensitivity

Additional load sensitivities were done to evaluate the low load and high load bookends using the updated forced outage rates.

- Base_300_270PVB_0Wd_Mar22Out_HiLd
  - 300MW of new firm generation and 270MW PV+BESS system is added to the Base resource plan. The 270MW PV+BESS is the approximate size of the next O'ahu variable RFP. Onshore wind was removed due to land use and community acceptance concerns.
  - With the high load forecast
- Base_300_270PVB_0Wd_170HE_Mar22Out_HiLd
  - Base_300_270PVB_0Wd_Mar22Out_HiLd with the removal of 170MW of utility thermal generation delayed.
- Base_300_270PVB_0Wd_280HE_Mar22Out_HiLd
  - Base_300_270PVB_0Wd_Mar22Out_HiLd with the removal of 280MW of utility thermal generation delayed.
- Base_300_270PVB_0Wd_Mar22Out_LwLd
  - Base_300_270PVB_0Wd_Mar22Out_HiLd with the low load forecast
- Base_300_270PVB_0Wd_wo170HE_Mar22Out_LwLd
  - Base_300_270PVB_0Wd_Mar22Out_LwLd with an additional 170MW of utility thermal generation deactivated.

- Base_400_270PVB_0Wd_Mar22Out_HiLd
    - 400MW of new firm generation and 270MW PV+BESS system is added to the Base resource plan. The 270MW PV+BESS is the approximate size of the next O’ahu variable RFP. Onshore wind was removed due to land use and community acceptance concerns.
    - With the high load forecast
- Base_400_270PVB_0Wd_170HE_Mar22Out_HiLd
    - Base_400_270PVB_0Wd_Mar22Out_HiLd with the removal of 170MW of utility thermal generation delayed.
- Base_400_270PVB_0Wd_280HE_Mar22Out_HiLd
    - Base_400_270PVB_0Wd_Mar22Out_HiLd with the removal of 280MW of utility thermal generation delayed.
- Base_400_270PVB_0Wd_Mar22Out_LwLd
    - Base_400_270PVB_0Wd_Mar22Out_HiLd with the low load forecast
- Base_400_270PVB_0Wd_wo170HE_Mar22Out_LwLd
    - Base_400_270PVB_0Wd_Mar22Out_LwLd with an additional 170MW of utility thermal generation removed.

Shown below in Figure 82 is the capacity of resources in 2029 for each case where 300MW of new firm generation was added.

Figure 83 shows the capacity of resources in 2029 for each case where 400MW of new firm generation was added. Due to rounding, the existing firm capacity may be slightly different from the amount of removed capacity that is accelerated/delayed in the case descriptions at the beginning of this section.

Figure 82. Probabilistic analysis – resource capacity summary, year2029. Load sensitivity with 300MW of new firm generation

Year 2029	Existing	Base_300_270PVB_0Wd_ Mar22Out	Base_300_270PVB_0Wd_ 170HE_Mar22Out	Base_300_270PVB_0Wd_ 280HE_Mar22Out	Base_300_270PVB_0Wd_ wo170HE_Mar22Out
Existing Firm	1,729	970	1,135	1,243	801
Existing PV	188	188	188	188	188
Existing Wind	123	123	123	123	123
CBRE	0	185	185	185	185
Stage Mililani / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94	94
Future PV	0	270	270	270	270
Future Wind	0	0	0	0	0
Future Firm Units	0	300 MW (6-50 MW CT)	300 MW (6-50 MW CT)	300 MW (6-50 MW CT)	300 MW (6-50 MW CT)
Total	**2,040**	**2,270**	**2,434**	**2,543**	**2,101**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh
Total	**0 MW / 0 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**

Figure 83. Probabilistic analysis – resource capacity summary, year 2029. Load sensitivity with 400MW of new firm generation

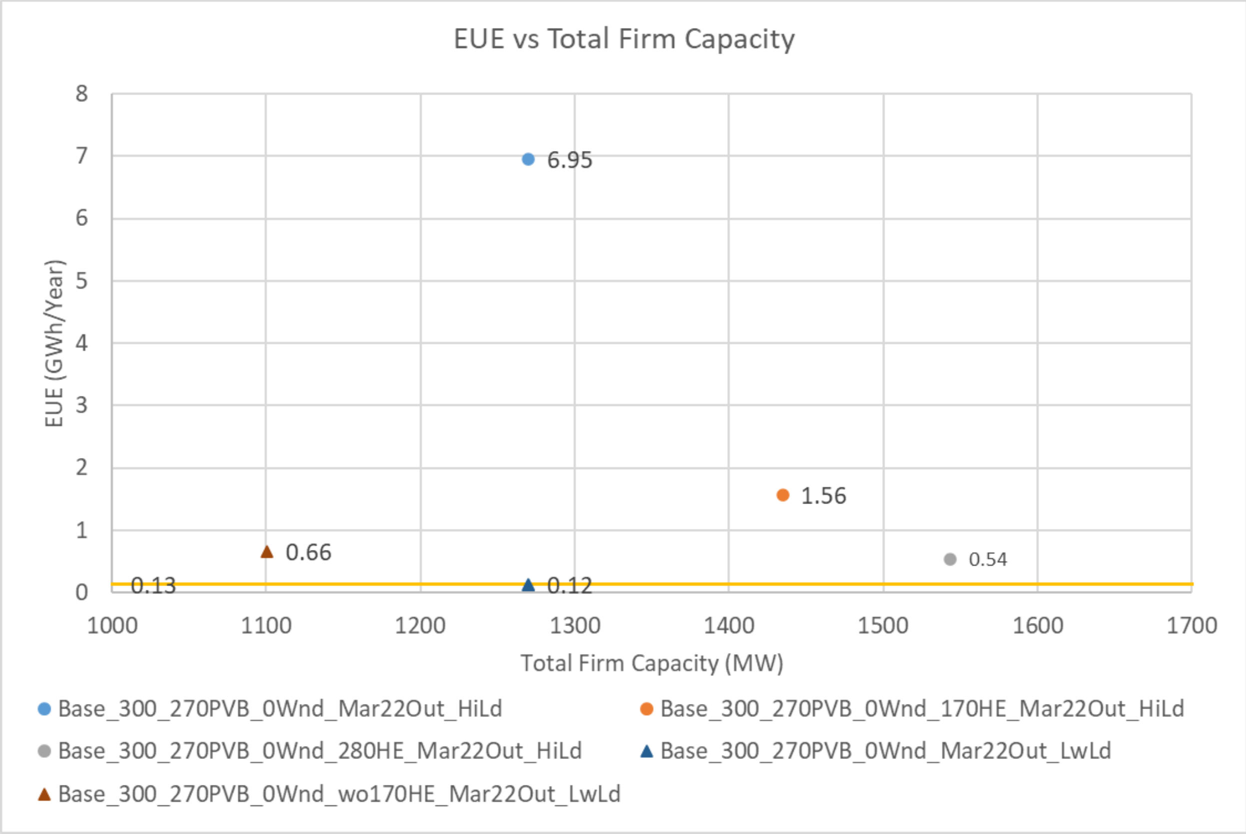
Year 2029	Existing	Base_400_270PVB_0Wd_ Mar22Out	Base_400_270PVB_0Wd_ 170HE_Mar22Out	Base_400_270PVB_0Wd_ 280HE_Mar22Out	Base_400_270PVB_0Wd_ wo170HE_Mar22Out
Existing Firm	1,729	970	1,135	1,243	801
Existing PV	188	188	188	188	188
Existing Wind	123	123	123	123	123
CBRE	0	185	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94	94
Future PV	0	270	270	270	270
Future Wind	0	0	0	0	0
Future Firm Units	0	400 MW (8-50 MW CT)	400 MW (8-50 MW CT)	400 MW (8-50 MW CT)	400 MW (8-50 MW CT)
Total	**2,040**	**2,370**	**2,534**	**2,643**	**2,201**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh
Total	**0 MW / 0 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**

Shown below in Figure 84 is the impact that the firm generation capacity and load forecast has on the various reliability metrics discussed earlier. This is for the case where 300MW of new firm generation is added. This information is also shown in Figure 85. As shown below, with 300MW of new firm generation, none of the reliability targets will be met under the high load forecast even with the delayed deactivation of 280MW of firm generation. With the low load forecast, the Stage 3 procurement target of 270MW paired PV and 300MW of firm generation, will still be short of the LOLE target.

Figure 84. Probabilistic analysis - results summary, year 2029. Load sensitivity with 300MW of new firm generation

Year 2029	Existing Firm Generation (MW)	New Firm Generation (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	1,729	0	1.18	1.30	2.90	0.13
High Load Forecast						
Base_300_270PVB_0Wd_Mar22Out_HiLd	970	300	10.10	19.42	48.01	6.95
Base_300_270PVB_0Wd_170HE_Mar22Out_HiLd	1,135	300	2.63	4.61	11.04	1.56
Base_300_270PVB_0Wd_280HE_Mar22Out_HiLd	1,243	300	1.00	1.82	4.02	0.54
Low Load Forecast						
Base_300_270PVB_0Wd_Mar22Out_LwLd	970	300	0.26	0.48	0.99	0.12
Base_300_270PVB_0Wd_wo170HE_Mar22Out_LwLd	801	300	1.51	3.012	5.91	0.66

Figure 85. EUE and total firm capacity in 2029. Load sensitivity with 300MW of new firm generation

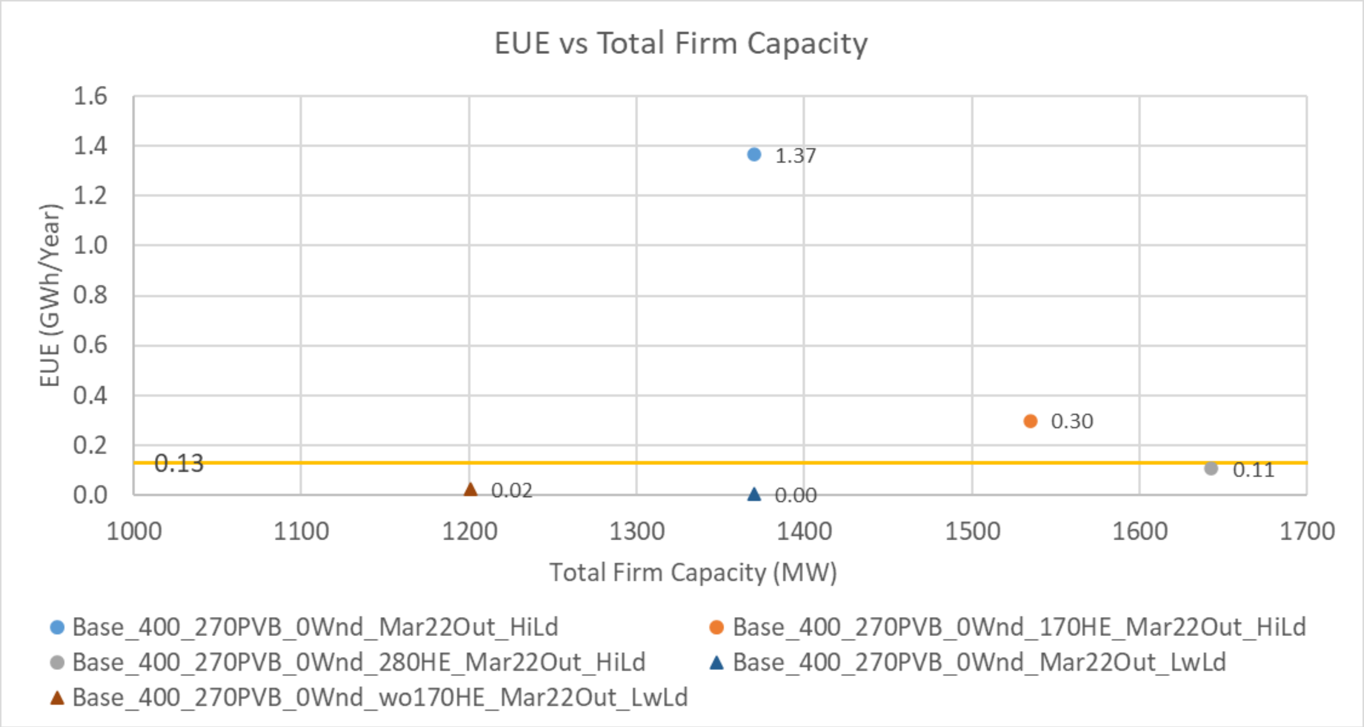


Shown below in Figure 86 is the impact that the firm generation capacity and load forecast has on the various reliability metrics discussed earlier. This is for the case where 400 MW of new firm generation is added. This information is also shown in Figure 87. As shown below, with 400 MW of new firm generation, under the high load forecast even with the delayed deactivation of 280 MW of firm generation LOLE will not meet the 0.1 metric. With the low load forecast, the Stage 3 procurement target of 270 MW paired PV and 400 MW of firm generation, the reliability targets are satsified. Also, with the low load forecast, and 400MW of firm generation, additional fossil-fuel generation capacity could be deactivated and acheive close to the reliability targets.

Figure 86. Probabilistic analysis - results summary, year 2029. Load sensitivity with 400MW of new firm generation

Year 2029	Existing Firm Generation (MW)	New Firm Generation (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	1,729	0	1.18	1.30	2.90	0.13
High Load Forecast						
Base_400_270PVB_0Wd_Mar22Out_HiLd	970	400	2.52	4.63	10.49	1.37
Base_400_270PVB_0Wd_170HE_Mar22Out_HiLd	1,135	400	0.65	1.12	2.59	0.30
Base_400_270PVB_0Wd_280HE_Mar22Out_HiLd	1,243	400	0.19	0.30	0.78	0.11
Low Load Forecast						
Base_400_270PVB_0Wd_Mar22Out_LwLd	970	400	0.03	0.04	0.09	0.00
Base_400_270PVB_0Wd_wo170HE_Mar22Out_LwLd	801	400	0.12	0.19	0.30	0.02

Figure 87. EUE and total firm capacity in 2029. Load sensitivity with 400MW of new firm generation



6.5.7 DER and EE Freeze Sensitivity

Shown below in Figure 88 is the amount of DER including distributed PV and BESS and EE assumed in the Freeze case versus the Base case. The EE in the freeze case includes the forecasted Codes and Standards. The DER in both the Base case and Freeze case includes degradation.

Figure 88. Forecasted 2029 DER and EE sales (GWh). Base and Freeze scenarios

2029 (Sales GWH)	Acquired and Future DER	Future EE
Base	1,384	992
Freeze	919	530

Using the latest outage rates, a few scenarios were tested to determine what firm capacity would be needed if the DER and EE freeze forecast were used.

- Base_300_270PVB_0Wnd_Fze_Mar22Out
    - Base case with 6-50MW CT generators added in 2029, 270 MW PV+ BESS, and 0MW onshore wind.
    - 270 MW paired PV is the approximate size of the Stage 3 procurement target. The paired BESS was assumed to have 3-hour duration, which is the same size as the paired BESS chosen by RESOLVE as the optimal amount. Onshore wind was removed due to land use and community acceptance concerns.
    - DGPV/DBESS amounts frozen at the end of 2020. EE amount was frozen at the end of 2021.
    - EV load was assumed to be unmanaged.
- Base_400_270PVB_0Wnd_Fze_Mar22Out
    - Base_300_270PVB_0Wnd_Mar22Out with 8-50MW CT generators added in 2029 instead of 6-50MW CT generators.
- Base_500_270PVB_0Wnd_Fze_Mar22Out
    - Base_300_270PVB_0Wnd_Mar22Out with 10-50MW CT generators added in 2029 instead of 6-50MW CT generators.

Shown below in Figure 89 is the capacity of resources in 2029 for these cases.

Figure 89. Probabilistic analysis – resource capacity summary, year 2029. DER Freeze sensitivity

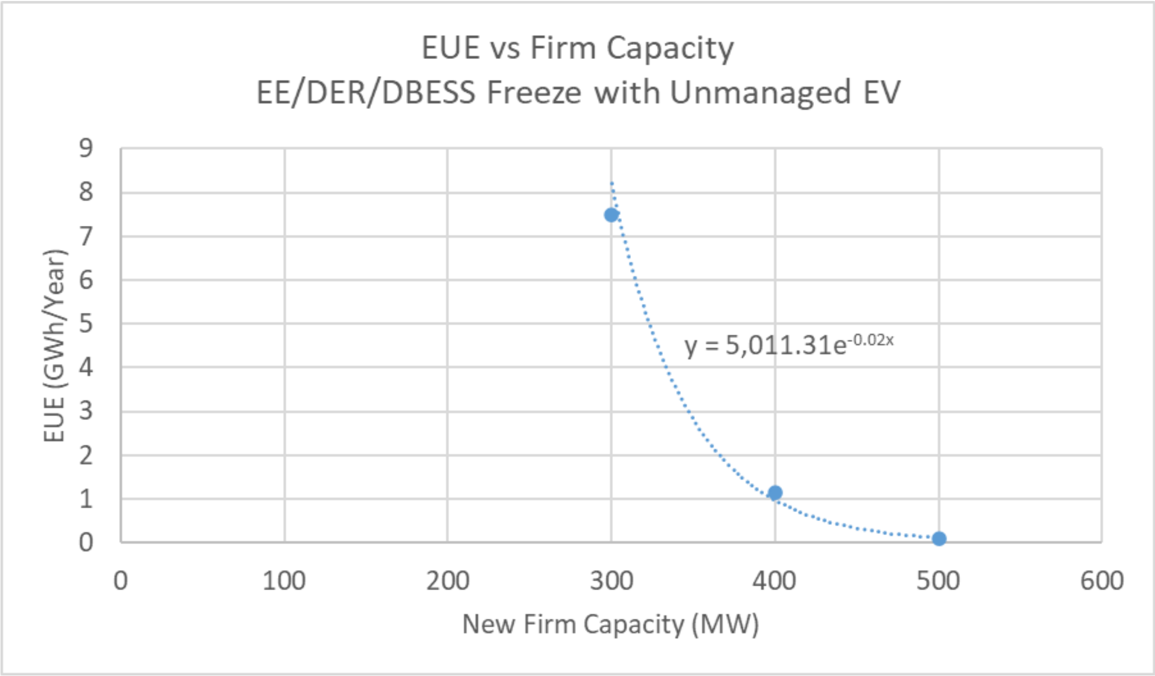
Year 2029	Existing	Base_300_270PVB_0Wnd_ Fze_Mar22Out	Base_400_270PVB_0Wnd_ Fze_Mar22Out	Base_500_270PVB_0Wnd_ Fze_Mar22Out
Existing Firm	1,729	970	970	970
Existing PV	188	188	188	188
Existing Wind	123	123	123	123
CBRE	0	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O‘ahu	0	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94
Future PV	0	270	270	270
Future Wind	0	0	0	0
Future Firm Units	0	300 MW (6-50 MW CT)	400 MW (8-50 MW CT)	500 MW (10-50 MW CT)
Total	**2,040**	**2,270**	**2,370**	**2,470**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh
Total	**0 MW / 0 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**

Shown below in Figure 90 is the impact that the new firm generation has on the various reliability metrics if the DER/EE were frozen and the EV charging was unmanaged. In this situation, with the DER frozen at 2021 levels and EE frozen at 2022 levels, the system load is approximately 7,500 GWh, resulting in an EUE target of approximately 0.15 GWh, or 0.002% of system load. A trendline can be used to estimate the amount of firm generation needed. Using the trendline provided in Figure 91, the new firm capacity needed is approximately 485 MW, or approximately 185 MW more. This empahsizes the importance role of customer resources providing grid flexibility and their contributions to resource adequacy.

Figure 90. Probabilistic analysis - results summary, year 2029. DER Freeze sensitivity

Year 2029	New Firm Generation (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	1.18	1.30	2.90	0.13
Base_300_270PVB_0Wd_Fze_Mar22Out	300	10.08	19.78	54.84	7.51
Base_400_270PVB_0Wd_Fze_Mar22Out	400	2.31	4.30	10.28	1.16
Base_500_270PVB_0Wd_Fze_Mar22Out	500	0.31	0.58	1.12	0.10

Figure 91. EUE and new firm capacity in 2029. DER Freeze sensitivity



6.5.8 Additional DER/DR Resources

There was some stakeholder inquiry into whether a Demand Response program using batteries could help reduce the new firm generation target in addition to the distributed resources already consdiered as shown in the previous section. A few scenarios were tested assuming additional short-duration energy storage was installed in 2029.

- Base_300_270PVB_0Wd_Mar22Out
    - Base case with 300 MW of new firm generation, 270 MW PV+ BESS, and 0MW onshore wind.
    - The 270MW PV+BESS is the approximate size of the next Oʻahu variable RFP. Onshore wind was removed due to land use and community acceptance concerns.
- Base_150_150MW2hrSaB_270PVB_0Wd_Mar22Out
    - Base_300_270PVB_0Wd_Mar22Out with 150MW of new firm generation replaced with 150MW-2hr Standalone BESS.
- Base_150_150MW12hrSaB_270PVB_0Wd_Mar22Out
    - Base_300_270PVB_0Wd_Mar22Out with 150MW of new firm generation replaced with 150MW-12hr Standalone BESS.
- Base_300_105MW2hrSaB_270PVB_0Wd_Mar22Out
    - Base_300_270PVB_0Wd_Mar22Out with an additional 105MW-2hr Standalone BESS.
- Base_400_270PVB_0Wd_Mar22Out
    - Base_300_270PVB_0Wd_Mar22Out with 8-50MW CT generators added in 2029 instead of 3-50MW CT generators.

Shown below in Figure 92 is the capacity of resources in 2029 for these cases.

Figure 92. Probabilistic analysis – resource capacity summary, year 2029. Additional DER/DR sensitivity

Year 2029	Existing	Base_300 _270PVB_0Wnd_ Mar22Out	Base_150_ 150MW2hrSaB_ 270PVB_0Wd_ Mar22Out	Base_150_ 150MW12hrSaB_ 270PVB_0Wd_ Mar22Out	Base_300_ 105MW2hrSaB_ 270PVB_0Wd_ Mar22Out	Base_400_ 270PVB_0Wnd_ Mar22Out
Existing Firm	1,729	970	970	970	970	970
Existing PV	188	188	188	188	188	188
Existing Wind	123	123	123	123	123	123
CBRE	0	185	185	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94	94	94
Future PV	0	270	270	270	270	270
Future Wind	0	0	0	0	0	0
Future Firm Units	0	300 MW (6-50 MW CT)	150 MW (3-50 MW CT)	150 MW (3-50 MW CT)	300 MW (6-50 MW CT)	400 MW (8-50 MW CT)
Total	**2,040**	**2,270**	**2,120**	**2,120**	**2,270**	**2,370**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	557 MW / 1,349 MWh	707 MW / 1,649 MWh	707 MW / 3,149 MWh	662 MW / 1,559 MWh	557 MW / 1,349 MWh
Total	**0 MW / 0 MWh**	**975 MW / 2,975 MWh**	**1,125 MW / 3,275 MWh**	**1,125 MW / 4,775 MWh**	**1,125 MW / 3,185 MWh**	**975 MW / 2,975 MWh**

Shown below in Figure 93 is the impact that the additional short-duration energy storage has on the various reliability metrics.

Figure 93. Probabilistic analysis - results summary, year 2029. Additional DER/DR sensitivity

Year 2029	New Firm Generation (MW)	New Paired PV (MW)	New Standalone Storage (MW/MWh)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	0	0MW / 0MWh	1.18	1.30	2.90	0.13
Base_300_270PVB _ 0Wd_Mar22Out	300	270	287 MW / 539 MWh	0.66	1.18	2.47	0.26
Base_150_ 150MW2hrSaB_ 270PVB_0Wd_ Mar22Out	150	270	437 MW / 839 MWh	6.96	13.37	31.32	4.49
Base_150_ 150MW12hrSaB_ 270PVB_0Wd_ Mar22Out	150	270	437 MW / 2,339 MWh	2.48	5.16	12.17	1.91
Base_300_270PVB _0Wnd_Mar22Out	300	270	287 MW / 539 MWh	0.66	1.18	2.47	0.26
Base_300_ 105MW2hrSaB_ 270PVB_0Wd_ Mar22Out	300	270	392 MW / 749 MWh	0.48	0.92	1.78	0.19
Base_400_270PVB _0Wnd_Mar22Out	400	270	287 MW / 539 MWh	0.04	0.05	0.09	0.01

Shown in Figure 94 is the impact that accelerating the additional short-duration energy storage has on the EUE and compares it to a long-duration storage and new firm generation with the same power output. As expected, while a longer-duration storage improves reliability more than the short-duration energy storage system, neither improves reliability as much as new firm generation with the same power output.

Shown in Figure 95 is the impact that adding short-duration energy storage to 300MW of new firm generation has on the reliability targets. While the addition of short-duration energy storage improves reliability, it does not improve reliability as much as a firm generator with similar power output.

Figure 94. EUE and total firm capacity in 2029. Additional DER/DR sensitivity

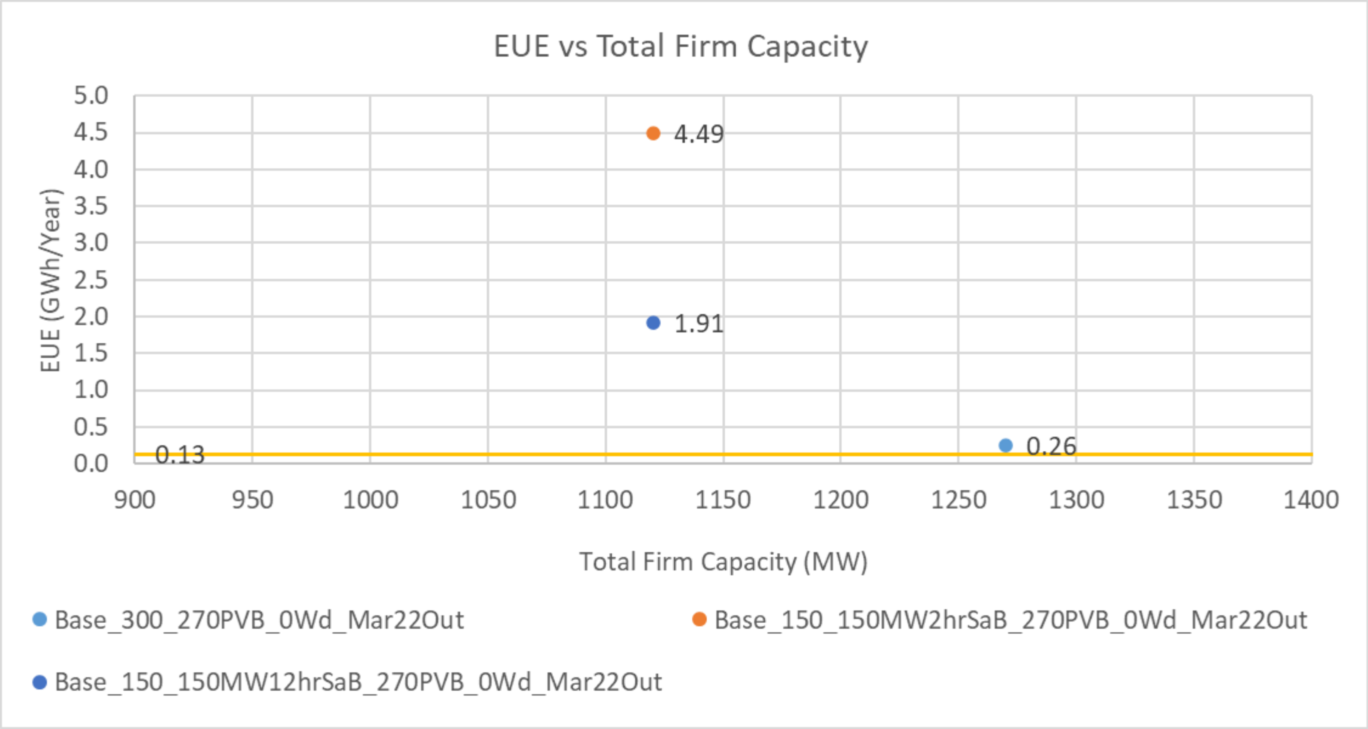
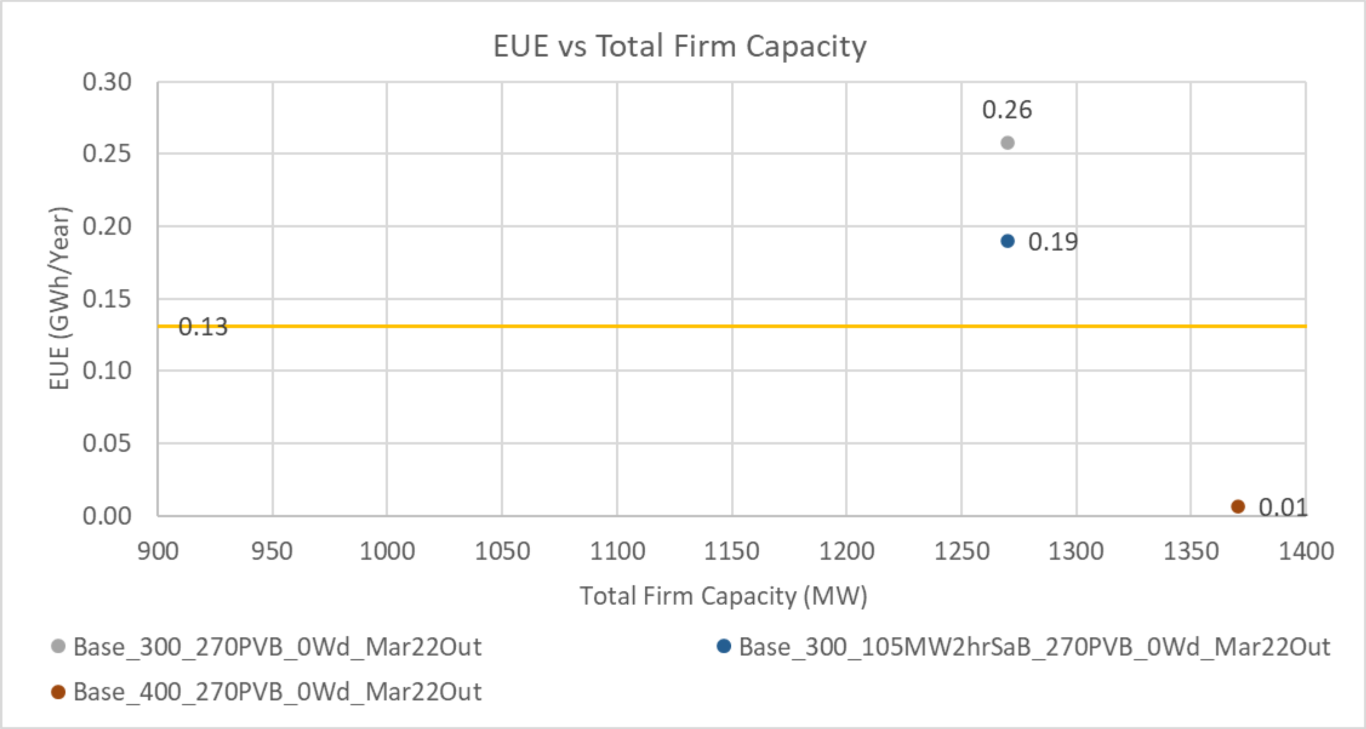


Figure 95. EUE and total firm capacity in 2029. Additional DER/DR sensitivity cont'd



6.5.9 Accelerated Offshore Wind

There was some stakeholder inquiry into how the firm generation target may be affected if offshore wind was capable of being developed earlier than 2035. Using the latest outage rates, a few scenarios were tested assuming offshore wind was installed in 2029.

- Base_270PVB_0Wnd_Mar22Out
  - Base case with 270 MW PV+ BESS and 0MW onshore wind.
  - 270 MW paired PV is the approximate size of the Stage 3 RFP target. The paired BESS was assumed to have 3-hour duration, which is the same size as the paired BESS chosen by RESOLVE as the optimal amount. Onshore wind was removed due to land use and community acceptance concerns.
- Base_270PVB_400OSW_Mar22Out
  - Base_270PVB_0Wnd_Mar22Out with 400 MW of offshore wind.
  - The size of the offshore wind was set at 400 MW because of stakeholder comments that this is the approximate size that would achieve the lowest Levelized Cost of Energy.
- Base_300_270PVB_0Wnd_Mar22Out
  - Base_270PVB_0Wnd_Mar22Out with 300 MW of new firm generation.
- Base_400_270PVB_0Wnd_Mar22Out
  - Base_270PVB_0Wnd_Mar22Out with 400 MW of new firm generation.
- Base_150_270PVB_400OSW_Mar22Out
  - Base_270PVB_400OSW_Mar22Out with 150 MW of firm generation.
- Base_300_270PVB_400OSW_Mar22Out
  - Base_270PVB_400OSW_Mar22Out with 300 MW of firm generation.

Shown below in Figure 96 is the capacity of resources in 2029 for these cases.

Figure 96. Probabilistic analysis - resource capacity summary, year 2029. Accelerated Offshore Wind sensitivity

Year 2029	Existing	Base_270PVB_ 0Wnd_ Mar22Out	Base_270PVB_ 400OSW_ Mar22Out	Base_300_270PVB_ 0Wnd_ Mar22Out	Base_400_270PVB_ 0Wnd_ Mar22Out	Base_150_270PVB_ 400OSW_ Mar22Out	Base_300_270PVB_ 400OSW_ Mar22Out
Existing Firm	1,729	970	970	970	970	970	970
Existing PV	188	188	188	188	188	188	188
Existing Wind	123	123	123	123	123	123	123
CBRE	0	185	185	185	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94	94	94	94
Future PV	0	270	270	270	270	270	270
Future Wind	0	0	400	0	0	400	400
Future Firm Units	0	0	0	300 MW (6-50 MW CT)	400 MW (8-50 MW CT)	150 MW (3-50 MW CT)	300 MW (6-50 MW CT)
Total	**2,040**	**1,970**	**2,370**	**2,270**	**2,370**	**2,520**	**2,670**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh
Total	**0 MW / 0 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**

Shown below in Figure 97 and Figure 98 is the impact that the accelerated offshore wind has on the various reliability metrics. While installing 400 MW of offshore wind helps to improve reliability and reduces the unserved energy to around 11 GWh, installing 300-400MW of firm generation shows a larger improvement on reliability and reduces the unserved energy to around 0.3 GWh or less.

Shown in Figure 97 and Figure 99 is the impact that accelerating offshore wind has on the new firm generation needed. With 400 MW of offshore wind, the EUE reliability target is only satisfied with an additional 300 MW of new firm generation. With only 150 MW of new firm generation and 400 MW of offshore wind, none of the reliability targets are met. Even in this scenario with 300 MW of new firm generation, the LOLE target is not met.

Figure 97: Probabilistic analysis - results summary, year 2029. Accelerated Offshore Wind sensitivity

Year 2029	New Firm Generation (MW)	Offshore Wind (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	0	1.18	1.30	2.90	0.13
Base_270PVB_0Wnd_Mar22Out	0	0	54.91	112.08	322.86	51.42
Base_270PVB_400OSW_Mar22Out	0	400	12.14	21.96	69.56	11.32
Base_300_270PVB_0Wnd_Mar22Out	300	0	0.66	1.18	2.47	0.26
Base_400_270PVB_0Wnd_Mar22Out	400	0	0.04	0.05	0.09	0.01
Base_270PVB_400OSW_Mar22Out	0	400	12.14	21.96	69.56	11.32
Base_150_270PVB_400OSW_Mar22Out	150	400	2.06	3.80	10.35	1.42
Base_300_270PVB_400OSW_Mar22Out	300	400	0.18	0.34	0.74	0.08

Figure 98. EUE and total firm capacity in 2029. Accelerated Offshore Wind sensitivity

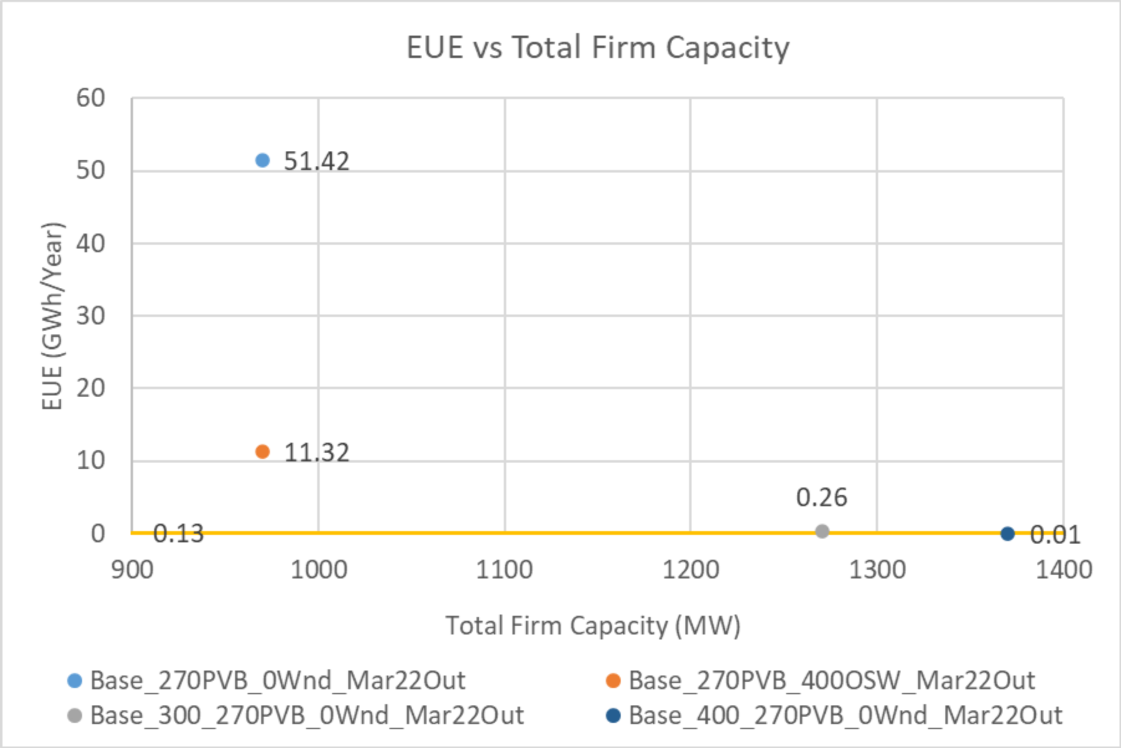
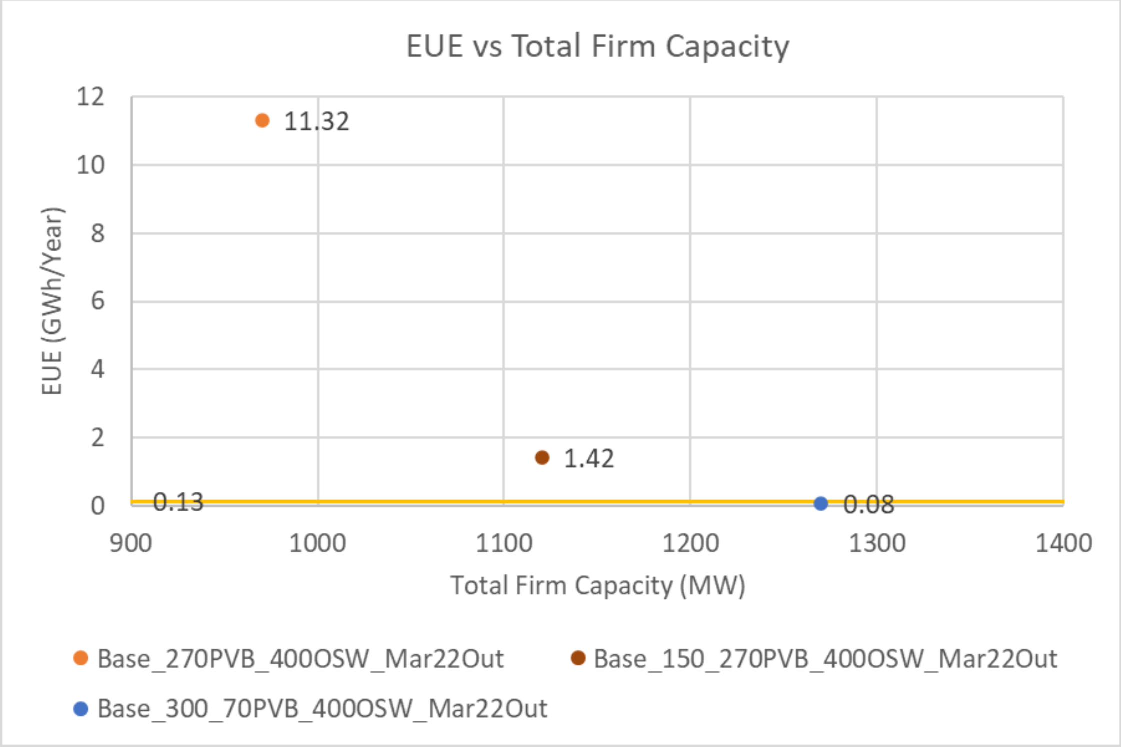


Figure 99. EUE and total firm capacity in 2029. Accelerated Offshore Wind sensitivity cont'd



Shown below in Figure 100 is what one of the worst days could look like for the Base_150_270PVB_400OSW_Mar22Out case where the new generation added consists of only 150MW of new firm generation, 270 MW of new paired renewables, and 400MW of new offshore wind. This day has one of the highest outages of thermal generators and one of the lowest renewable generation. Figure 101 shows the day with the largest amount of available renewable energy.

Figure 100. Sample dispatch for the day with the highest amount of unserved energy. Base_150_270PVB_400OSW_Mar22Out scenario

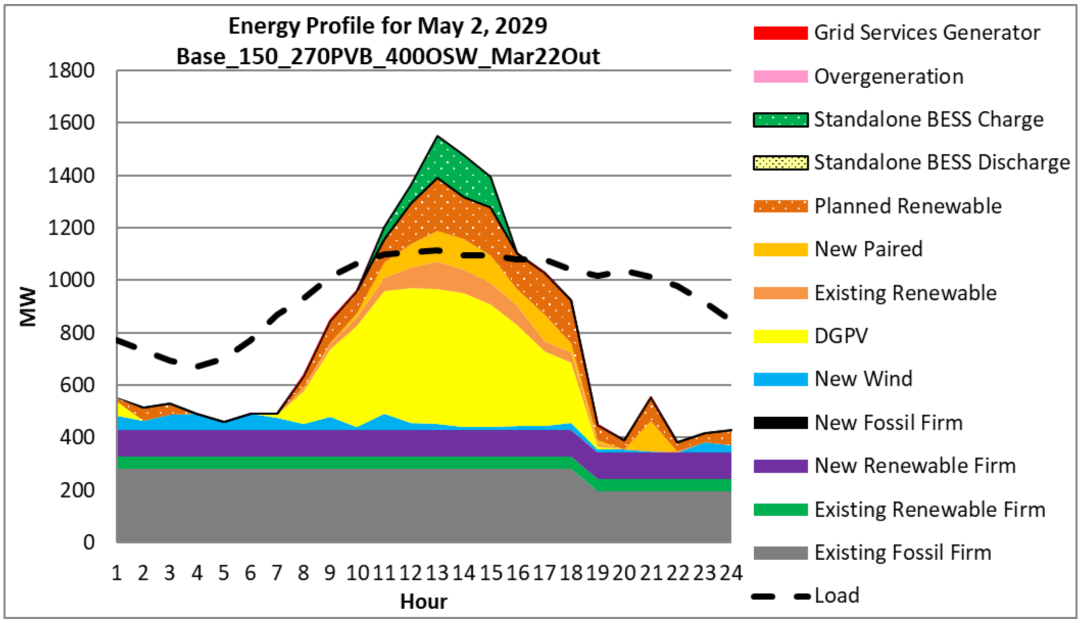
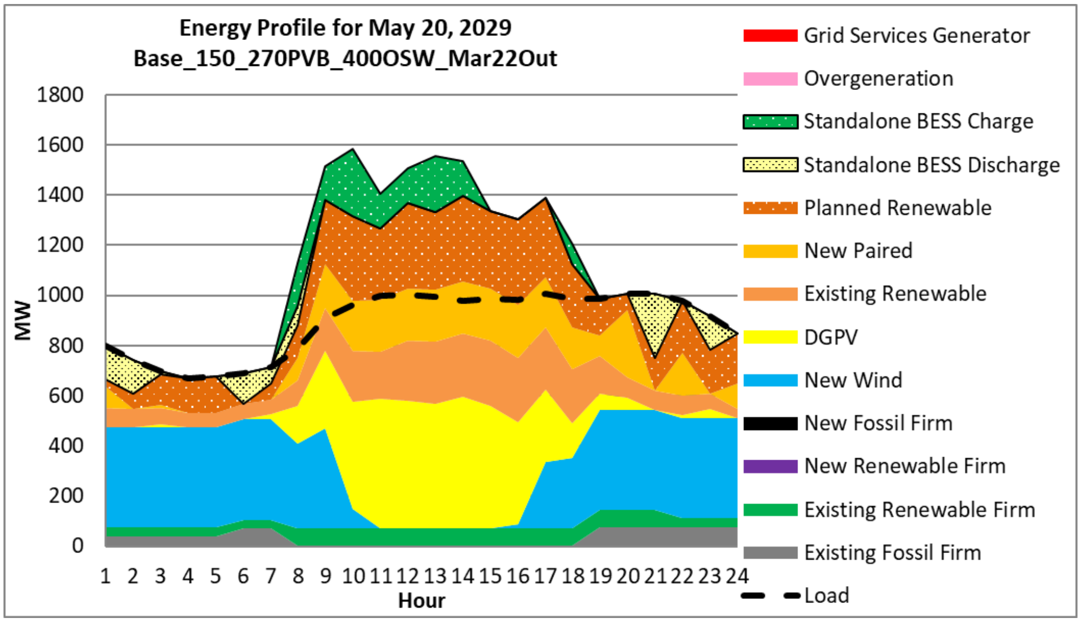


Figure 101. Sample dispatch for the day with the highest amount of available variable renewable generation. Base_150_270PVB_400OSW_Mar22Out scenario



6.5.10 Planning for Extreme Events

Initial analysis was performed to evaluate potential extreme events and their impact on reliability. More work must be done in this area to determine the magnitude and impact an extreme event could have on the system and whether investments should be made to mitigate such events. This analysis, however, provides an initial starting point.

A forced outage caused by an extreme event may last several weeks or longer. This forced outage may be caused by various factors such as transmission line outages, wildfires and supply-chain issues, among other things. Resources were assumed to be out for 438 consecutive hours, or 5% of the year. The assumption to use a 5% outage rate for transmission outages is consistent with the LA100 Renewable Energy Study. The scenarios analyzed were:

- Base_Accel_163WindOut_5pct – Base_Accel case with 438 consecutive hours of forced outage on the 163MW onshore wind.
- Base_Accel_300BESSOut_5pct – Base_Accel case with 438 consecutive hours of forced outage on 300MW/600MWh Standalone BESS. The 2-hour standalone battery duration was determined by RESOLVE.
- Base_Accel_300PVBOut_5pct – Base_Accel case with 438 consecutive hours of forced outage on 300MW paired PV with 300MW/900MWh paired BESS. The 3-hour paired battery duration was determined by RESOLVE.
- Base_Accel_508_Staggered_163WindOut_5pct – Base_Accel_508_Staggered case with 438 consecutive hours of forced outage on the 163MW onshore wind.
- Base_Accel_508_Staggered _300BESSOut_5pct – Base_Accel_508_Staggered case with 438 consecutive hours of forced outage on 300MW/600MWh Standalone BESS. The 2-hour standalone battery duration was determined by RESOLVE.
- Base_Accel_508_Staggered _300PVBOut_5pct – Base_Accel_508_Staggered case with 438 consecutive hours of forced outage on 300MW paired PV with 300MW/900MWh paired BESS. The 3-hour paired battery duration was determined by RESOLVE.
- Base_Accel_508_Staggered_300FirmOut_5pct – Base_Accel_508_Staggered case with 438 consecutive hours of forced outage on the 300MW new firm generation.

Figure 102 shows the impact that the higher outage rates have on the reliability metrics.

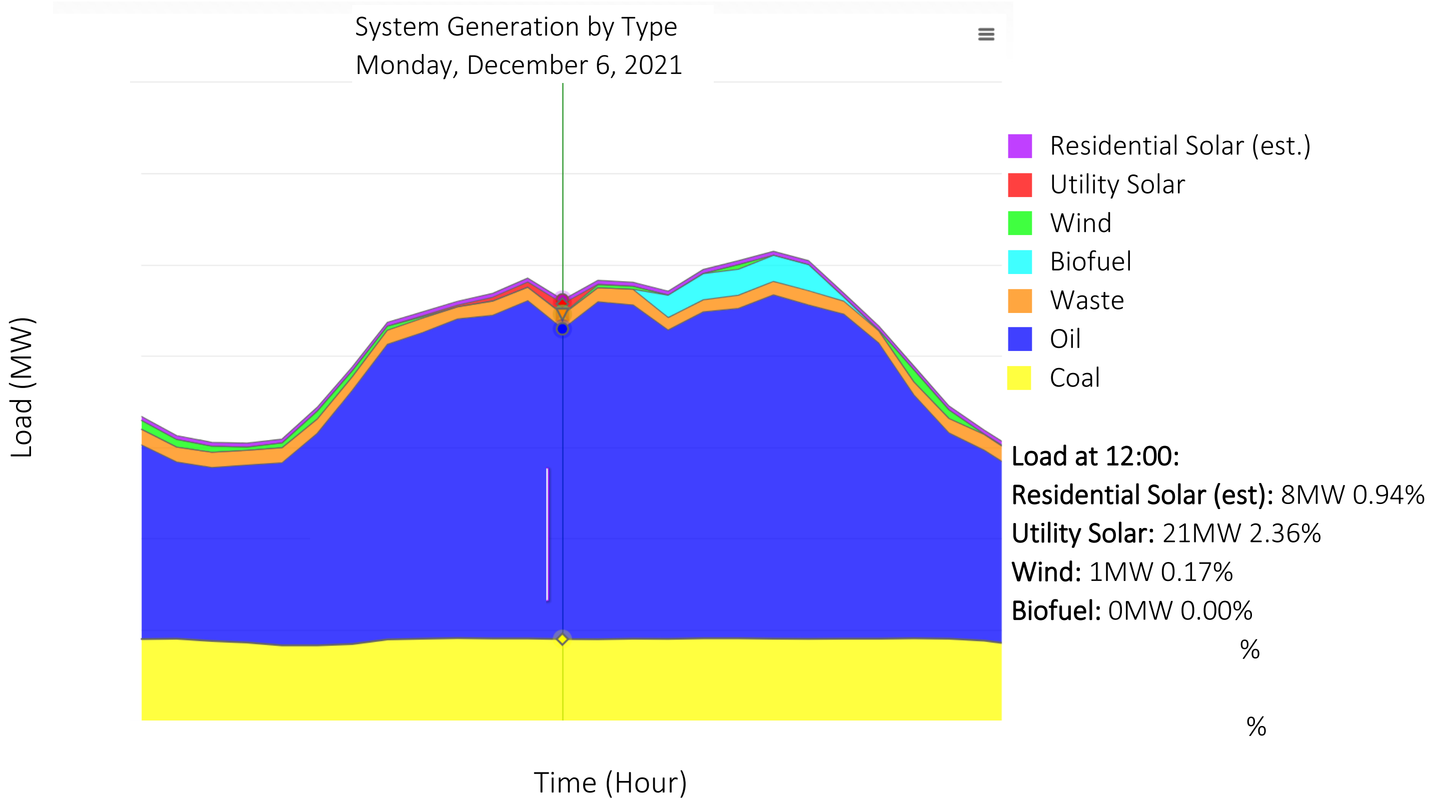
Figure 102. Probabilistic analysis - results summary, year 2029. Base cases sensitivity with extended forced outage

Year 2029	New Firm Generation (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	1.18	1.30	2.90	0.13
Base_Accel	0	0.52	1.05	2.01	0.44
Base_Accel_163WindOut_5pct	0	0.50	1.02	1.97	0.44
Base_Accel_300BESSOut_5pct	0	0.53	1.09	1.98	0.44
Base_Accel_300PVBOut_5pct	0	0.54	1.10	2.02	0.45
Base_Accel_508_Staggered	300	0.00	0.00	0.00	0.00
Base_Accel_508_Staggered_163WindOut_5pct	300	0.00	0.00	0.00	0.00
Base_Accel_508_Staggered_300BESSOut_5pct	300	0.00	0.00	0.00	0.00
Base_Accel_508_Staggered_300PVBOut_5pct	300	0.00	0.00	0.00	0.00
Base_Accel_508_Staggered_300FirmOut_5pct	300	0.03	0.06	0.10	0.02

As shown, by comparing the cases with the 300 MW of new firm generation to the cases without, the addition of firm generation eliminated the unserved energy in most cases. Focusing on the cases with the 300 MW of new firm generation, only the case where the firm generation was forced out for 438 consecutive hours showed unserved energy. This highlights the value that firm generation provides to the system. In the cases where the onshore wind, paired PV, or standalone BESS is removed from service, there is no expected unserved energy, indicating the remaining resources were able to adequately meet demand. Only in the case where the new firm resources were removed from service do the results show unserved energy, indicating that the remaining resources were not able to meet demand.

One area that warrants further exploration is the occurrence of poor weather conditions such as the Kona Low experienced on O'ahu in December 2021. As shown in Figure 103, on December 6, 2021, an unusually low amount of DG-PV, utility scale solar and wind was available on this day. About 92% of the load was supplied by firm generation. In 2030, without sufficient renewable firm generation, it's possible that there could be insufficient generation to charge energy storage systems and supply the load.

Figure 103. Generation by resource type on December 6, 2021



There are several considerations in evaluating these potentially high impact events:

- The resource adequacy does attempt to account for "extreme events", but the impacts are weighted to the probability of occurrence, thus excluding mitigation measures for tail events. The 80th percentile hourly dependable capacity for renewable resources and probabilistic resource adequacy would not account for these events. Further, by convention, the probabilistic resource adequacy metrics are reported as the average of the total samples.
- The likelihood and negative impact of a tail event is reduced in two ways: increase in probability of generation availability (adding more of a resource, improving outage rates, etc.) and decrease in unavailability overlap (flexible generation, diversification). Risk can be reduced by focusing on only one of these aspects, but the effectiveness of each mitigation is augmented when addressed at the same time. While possible to meet demand with a portfolio comprised of a singular resource type, the repercussions of a tail event will be amplified, especially if the singular resource has a high chance of being collectively unavailable at the same time as is the case with solar.

During this low frequency / high impact event, each subsequent period of poor renewable generation increases the likelihood of a cascading unavailability at a later time. As one of the more flexible resource types, diversification with firm resources reduces the risks of these events by acting as a buffer to absorb the ripple effects caused by low renewable generation and storage with low state of charge.

7 PRODUCTION COST MODELING AND OPERATIONS UNDER THE PROCUREMENT PLAN

The resource adequacy analysis found that 500-700 MW of new renewable firm capacity would provide sufficient reliability over a range of future scenarios. This amount of new firm generation could also facilitate removal or deactivation of older fossil-fuel generating units depending on the system conditions, such as number of new renewable resources and the load forecasts at the time.

To verify the operations under the procurement scenario, production cost simulations were evaluated using a mix of flexible generators and base loaded renewable firm generators to inform how different technologies would be operated.

For the 500 MW target, a 200 MW combined cycle plant (CC) and 6 quick starting 50 MW combustion turbine (CT) generators were added. The 600 MW target added 100 MW of quick starting internal combustion engines (ICE), similar to Schofield Generating Station, and the 700 MW target includes the CC and CTs in the 500 MW target plus a 180-200 MW of base loaded renewable steam generation that could represent repowering of existing fossil-fuel steam generation facilities.

The characteristics of the different renewable firm generators being considered is shown in Figure 104.

Figure 104. Operating characteristics of firm generators

	RE-CT	RE-CC	RE-ICE	RE-Steam/Biomass
Max Capacity (MW)	300 MW (50MW x 6 units)	208 MW	99 MW (9 MW x 11 units)	180 MW (20 MW x 9 units)
Min Stable Level per Unit (MW)	13.75 MW	29.07 MW	3.96 MW	8 MW
Ramp Rate (MW/min)	50	50	1.66	2.5
Start Time (min)	5	30	5	5
Capital – 2029 ($/kW)	1,416	1,670	2,988	7,111
Fixed O&M – 2029 ($/kWyr)	31	41	46	224
Variable O&M – 2029 ($/MWh)	7	3	34	7
Fuel – 2029 ($/mmbtu)	Diesel – 18.85 Biodiesel – 37.30	Diesel – 18.85 Biodiesel – 37.30	ULSD - 20.42 Biodiesel – 37.30	Biomass – 4.76 Biodiesel – 37.30

The biomass option has a relatively higher fixed cost than the renewable CT, CC and ICE options. However, because of its lower variable cost, it can be a cost-effective option if the firm capacity is expected to have higher run hours and stable usage. Otherwise, in a situation where the firm capacity acts more as a standby capacity that may not run often, the CT, CC and ICE could be more cost effective.

7.1 Operations under the Procurement Plan

As discussed in Section 6.2.2, firm capacity between 508 MW and 688 MW would address most of the capacity shortfall requirements. A production simulation was performed in PLEXOS using the Base staggered resource plans provided in Figure 129 and the Land Constrained staggered resource plans provided in

Figure 130 to determine how the new firm units would operate. One set of simulations assumed the new CT, CC, and ICE units were on biofuel, and a separate set of simulations assumed the new CT, CC, and ICE units were on fossil-fuel.

As shown in the following sections, even in the cases where the new firm units are on biofuel, they will still operate. Given the significantly higher cost of biofuel over fossil-fuel, this indicates the value these units provide to the system to meet demand, even when they are on biofuel. Furthermore, since the new units are more efficient than the current fleet of firm generators, when the new units are on fossil-fuel rather than biofuel, they operate significantly more. As a result, whether the new units are on biofuel or fossil-fuel, they will provide value to the system either through providing capacity to meet demand or through better efficiency compared to existing generators.

As shown below, the simulations still project large amounts of variable renewable generation being used to meet load, even with the addition of new firm generation. The simulations also project that even in the Land Constrained cases, which have the least amount of renewables added, the RPS-A is projected to be over 50% by 2030.

7.1.1 Characteristics – Capacity Factor

Shown below in Figure 105 is the capacity factor for the new firm resources in each of the Base staggered resource plans and Figure 106 is the capacity factor for the existing firm generators in the Base_508_Staggered case.

Figure 105. Capacity factor of new firm units in Base (staggered) cases

Capactiy Factor (%)	Base_508 Staggered		Base_607 Staggered			Base_688 Staggered		
Year	RE-CT	RE-CC	RE-CT	RE-ICE	RE-CC	RE-CT	BioM	RE-CC
2025	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2026	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2027	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2028	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2029	12%	N/A	4%	26%	N/A	1%	97%	N/A
2030	5%	N/A	2%	10%	N/A	0%	76%	N/A
2031	5%	N/A	2%	8%	N/A	0%	73%	N/A
2032	4%	N/A	1%	8%	N/A	0%	72%	N/A
2033	0%	10%	0%	2%	11%	0%	69%	1%
2034	1%	8%	0%	2%	9%	0%	66%	1%
2035	0%	6%	0%	1%	6%	0%	59%	0%

Figure 106. Capacity factor of existing firm units in Base_508_Staggered case

Capacity Factor (%)	Existing Thermal Capacity Factor Base_508_Staggered								
Year	CIP1	DSG	SCH-1	Kahe 1	Kahe 2	Kahe 3	Kahe 4	Kahe 5	Kahe 6
2025	5.59	6.85	1.26	69.12	59.63	41.36	63.30	14.77	16.91
2026	11.12	12.63	2.52	57.81	61.42	47.33	67.14	9.91	3.08
2027	2.08	2.75	6.32	27.82	51.73	18.75	61.03	9.48	7.60
2028	2.85	3.07	9.19	44.00	49.03	27.57	52.46	3.03	2.42
2029	14.54	4.81	61.79	N/A	N/A	77.54	87.94	21.94	9.57
2030	4.77	1.52	25.86	N/A	N/A	10.61	33.80	1.36	0.57
2031	5.43	0.75	25.59	N/A	N/A	10.76	31.25	0.46	1.03
2032	4.38	0.91	23.78	N/A	N/A	9.19	32.10	3.10	0.23
2033	1.79	0.29	30.43	N/A	N/A	23.25	40.79	8.84	0.52
2034	1.60	0.41	29.14	N/A	N/A	21.59	38.39	5.85	0.95
2035	1.42	0.32	23.07	N/A	N/A	17.02	32.49	2.03	0.26

Figure 107. Capacity factor of existing firm units in Base_508_Staggered case cont'd

Capacity Factor (%)	Existing Thermal Capacity Factor Base_508_Staggered					
Year	Waiau 5	Waiau 6	Waiau 7	Waiau 8	Waiau 9	Waiau 10
2025	27.43	21.45	69.44	65.42	17.39	9.67
2026	38.90	27.98	60.68	62.88	15.05	12.96
2027	N/A	N/A	64.32	62.47	11.18	4.10
2028	N/A	N/A	66.45	64.30	14.50	6.74
2029	N/A	N/A	76.02	71.60	66.71	51.65
2030	N/A	N/A	32.78	36.15	24.56	20.48
2031	N/A	N/A	33.05	29.23	22.40	18.51
2032	N/A	N/A	31.96	28.92	19.10	16.42
2033	N/A	N/A	N/A	N/A	25.69	18.92
2034	N/A	N/A	N/A	N/A	24.35	18.55
2035	N/A	N/A	N/A	N/A	18.52	14.47

Shown below in Figure 108 is the capacity factor for the new firm resources in each of the Land Constrained staggered resource plans and Figure 109 is the capacity factor for the existing firm generators in the LC_508_Staggered case.

Figure 108. Capacity factor of new firm units in Land Constrained (staggered) cases

Capacity Factor (%)	LC_508_Staggered		LC_607_Staggered			LC_688_Staggered			
Year	RE-CT	RE-CC	RE-CT	RE-ICE	RE-CC	RE-CT		BioM	RE-CC
2025	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
2026	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
2027	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
2028	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
2029	24%	N/A	10%	44%	N/A	4%	97%	N/A	
2030	13%	N/A	6%	21%	N/A	3%	95%	N/A	
2031	13%	N/A	6%	23%	N/A	2%	96%	N/A	
2032	23%	N/A	12%	36%	N/A	5%	96%	N/A	
2033	11%	56%	4%	23%	50%	1%	96%	24%	
2034	12%	57%	5%	27%	50%	2%	96%	24%	
2035	3%	31%	1%	9%	28%	0%	89%	11%	

Figure 109. Capacity factor of existing firm units in LC_508_Staggered case

Capacity Factor (%)	Existing Thermal Capacity Factor LC_508_Staggered								
Year	CIP1	DSG	SCH-1	Kahe 1	Kahe 2	Kahe 3	Kahe 4	Kahe 5	Kahe 6
2025	6.00	6.68	1.09	69.14	59.65	41.08	63.08	14.79	16.76
2026	10.92	11.68	2.30	58.60	61.25	47.38	67.06	9.93	3.11
2027	4.67	5.41	10.53	52.81	62.21	49.44	70.21	10.26	5.32
2028	3.73	3.91	11.85	61.57	59.80	51.11	59.24	5.08	13.61
2029	22.68	5.02	77.84	N/A	N/A	81.90	90.17	23.26	16.46
2030	8.93	2.88	49.93	N/A	N/A	73.21	82.77	22.96	25.52
2031	11.19	2.41	60.84	N/A	N/A	83.21	77.34	11.98	21.60
2032	17.50	8.00	72.42	N/A	N/A	65.13	86.68	14.57	2.42
2033	15.42	2.64	86.15	N/A	N/A	86.59	85.35	24.07	9.08
2034	16.17	2.93	86.41	N/A	N/A	88.50	79.26	15.77	19.42
2035	6.25	1.12	68.10	N/A	N/A	70.58	81.73	10.07	15.55

Figure 110. Capacity factor of existing firm units in LC_508_Staggered case cont'd

Capacity Factor (%)	Existing Thermal Capacity Factor LC_508_Staggered					
Year	Waiau 5	Waiau 6	Waiau 7	Waiau 8	Waiau 9	Waiau 10
2025	27.09	21.30	69.54	65.63	16.98	10.07
2026	40.14	28.08	60.15	62.81	14.53	12.59
2027	N/A	N/A	73.22	69.59	19.32	7.83
2028	N/A	N/A	73.64	70.54	20.24	10.14
2029	N/A	N/A	77.35	73.80	80.38	69.35
2030	N/A	N/A	79.81	81.53	50.06	36.85
2031	N/A	N/A	87.78	87.39	53.47	43.51
2032	N/A	N/A	74.42	77.12	56.75	56.67
2033	N/A	N/A	N/A	N/A	76.80	63.03
2034	N/A	N/A	N/A	N/A	75.90	69.28
2035	N/A	N/A	N/A	N/A	57.37	47.38

The new CC, SC, and ICE units were assumed to be on biodiesel while existing steam units located at Kahe and Waiau were assumed to be on low-sulfur fuel oil (LSFO). As expected, due to the higher cost of biodiesel compared to LSFO, the new CC, SC, and ICE units had lower utilization and were primarily used as standby capacity; a critical function that these generators serve to mitigate the risks of weather dependent resources. The biomass fuel cost was based on the 2021 NREL Annual Technology Baseline, which was significantly lower than the LSFO fuel cost assumed. As a result, the biomass generator ran considerably more. As the existing generators are deactivated, the capacity factor of the remaining generators increases, which suggests greater burden on the old existing generators, which may lead to increasing outage rates and worsening reliability.

The same production simulations were performed, this time assuming the new CC and SC were on diesel and the new ICE was on ultra-low sulfur diesel (ULSD). This illustrates how units would be dispatched if all generators were using the same fuel type. This does not imply that the new firm generators acquired would necessarily be operated on diesel fuel. Shown below in Figure 111 is the capacity factor for the new firm resources in each of the Base staggered resource plans when the new CC, SC and ICE are fueled by diesel.

Figure 111. Capacity factor of new firm units in Base (staggered fossil) cases

Capacity Factor (%)	Base_508 Staggered_Fossil		Base_607 Staggered_Fossil			Base_688 Staggered_Fossil		
Year	CT	CC	CT	ICE	CC	CT	BioM	CC
2025	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2026	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2027	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2028	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2029	47%	N/A	29%	73%	N/A	14%	97%	N/A
2030	19%	N/A	12%	52%	N/A	3%	76%	N/A
2031	17%	N/A	10%	49%	N/A	1%	73%	N/A
2032	16%	N/A	10%	47%	N/A	1%	72%	N/A
2033	2%	53%	0%	12%	52%	0%	69%	12%
2034	2%	48%	0%	11%	47%	0%	66%	9%
2035	1%	38%	0%	4%	38%	0%	59%	5%

Figure 112. Capacity factor of existing firm units in Base_508_Staggered_Fossil case

Capacity Factor (%)	Existing Thermal Capacity Factor Base_508 Staggered_Fossil								
Year	CIP1	DSG	SCH-1	Kahe 1	Kahe 2	Kahe 3	Kahe 4	Kahe 5	Kahe 6
2025	5.79	6.61	1.23	68.79	59.57	41.46	63.17	14.75	16.90
2026	11.03	12.40	2.43	57.99	61.13	47.13	67.08	9.91	3.09
2027	2.31	2.58	6.23	26.50	50.35	20.22	61.22	9.54	7.96
2028	3.05	2.68	9.26	42.48	50.20	27.60	52.73	2.98	1.09
2029	1.29	0.78	3.76	N/A	N/A	73.23	86.37	21.64	10.80
2030	0.70	0.92	3.30	N/A	N/A	10.16	32.78	1.35	0.90
2031	0.79	0.69	3.43	N/A	N/A	9.66	31.40	0.41	0.86
2032	0.36	0.45	2.87	N/A	N/A	9.10	30.10	3.03	0.94
2033	0.03	0.01	0.28	N/A	N/A	5.31	9.20	0.29	0.31
2034	0.03	0.00	0.38	N/A	N/A	5.75	7.61	1.07	0.51
2035	0.01	0.00	0.06	N/A	N/A	1.88	7.09	0.47	0.02

Figure 113. Capacity factor of existing firm units in Base_508_Staggered_Fossil case cont'd

Capacity Factor (%)	Existing Thermal Capacity Factor Base_508 Staggered_Fossil					
Year	Waiau 5	Waiau 6	Waiau 7	Waiau 8	Waiau 9	Waiau 10
2025	28.05	20.45	69.94	65.34	17.35	9.43
2026	40.91	28.62	60.49	62.67	14.61	12.56
2027	N/A	N/A	63.32	62.83	11.92	4.48
2028	N/A	N/A	67.76	64.35	14.95	6.88
2029	N/A	N/A	75.46	71.05	6.18	2.70
2030	N/A	N/A	36.06	31.28	2.47	1.08
2031	N/A	N/A	33.06	31.02	2.31	1.39
2032	N/A	N/A	30.99	26.92	1.54	1.35
2033	N/A	N/A	N/A	N/A	0.14	0.21
2034	N/A	N/A	N/A	N/A	0.18	0.08
2035	N/A	N/A	N/A	N/A	0.03	0.00

Shown below in Figure 114 is the capacity factor for the new firm resources in each of the Land Constrained staggered resource plans when the new CC, SC and ICE are on fossil-fuel.

Figure 114. Capacity factor of new firm units in Land Constrained (staggered fossil) cases

Capacity Factor (%)	LC_508 Staggered_Fossil		LC_607 Staggered_Fossil			LC_688 Staggered_Fossil		
Year	CT	CC	CT	ICE	CC	CT	BioM	CC
2025	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2026	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2027	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2028	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2029	65%	N/A	51%	81%	N/A	28%	97%	N/A
2030	38%	N/A	28%	65%	N/A	19%	96%	N/A
2031	44%	N/A	29%	64%	N/A	19%	96%	N/A
2032	55%	N/A	41%	69%	N/A	23%	96%	N/A
2033	39%	94%	24%	63%	94%	16%	96%	81%
2034	40%	93%	24%	64%	93%	18%	96%	81%
2035	24%	82%	16%	59%	82%	7%	89%	64%

Figure 115. Capacity factor of existing firm units in LC_508_Staggered_Fossil case

Capacity Factor (%)	Existing Thermal Capacity Factor LC_508 Staggered_Fossil								
Year	CIP1	DSG	SCH-1	Kahe 1	Kahe 2	Kahe 3	Kahe 4	Kahe 5	Kahe 6
2025	5.31	6.40	1.15	70.35	59.55	40.84	63.13	14.84	16.95
2026	10.72	11.94	2.47	59.17	61.00	47.37	67.08	9.91	3.03
2027	3.38	3.36	7.07	48.23	61.71	43.40	67.75	10.28	23.31
2028	4.01	4.10	12.68	61.74	59.82	48.48	59.04	4.79	13.68
2029	4.39	4.30	13.69	N/A	N/A	79.01	88.74	22.64	14.58
2030	1.51	1.36	7.21	N/A	N/A	69.41	80.85	22.65	24.70
2031	1.29	1.01	7.55	N/A	N/A	76.49	75.03	11.37	20.40
2032	5.30	5.81	15.30	N/A	N/A	60.64	84.57	14.25	2.74
2033	0.98	0.91	4.68	N/A	N/A	67.68	72.69	20.41	7.44
2034	1.44	0.97	7.13	N/A	N/A	69.77	68.97	13.41	15.85
2035	0.34	0.21	1.59	N/A	N/A	32.99	55.21	3.48	4.04

Figure 116. Capacity factor of existing firm units in LC_508_Staggered_Fossil case cont'd

Capacity Factor (%)	Existing Thermal Capacity Factor LC_508 Staggered_Fossil					
Year	Waiau 5	Waiau 6	Waiau 7	Waiau 8	Waiau 9	Waiau 10
2025	27.89	21.10	69.62	65.95	16.26	8.91
2026	40.36	27.71	60.31	62.77	14.64	12.57
2027	N/A	N/A	70.59	66.84	13.68	4.25
2028	N/A	N/A	73.63	71.21	20.84	11.16
2029	N/A	N/A	77.30	73.79	19.60	10.31
2030	N/A	N/A	78.89	80.11	8.48	3.92
2031	N/A	N/A	87.55	86.61	7.15	3.24
2032	N/A	N/A	73.57	76.07	12.26	10.25
2033	N/A	N/A	N/A	N/A	3.07	1.30
2034	N/A	N/A	N/A	N/A	4.96	2.98
2035	N/A	N/A	N/A	N/A	1.21	0.54

In the simulations where the new CC and CT were assumed to be on diesel and the new ICE was assumed to be on ultra-low sulfur diesel, the firm units run considerably more because the cost of fuel is relatively similar to existing generators as opposed to the relatively higher price of biofuel assumed in the renewable fuel production simulations.

7.1.2 Characteristics – Daily Dispatch Chart

Shown below in Figure 117 is the dispatch of the new firm renewables for a high renewable day in 2029, 2030, and 2033 for the Base_508_Staggered case. Shown below Figure 118 is the dispatch of the new firm renewables for a low renewable day in 2029, 2030, and 2033 for the Base_508_Staggered case.

In the daily charts, resources listed as "New" were resources selected by RESOLVE, Planned Renewables are renewable resources that are not yet in service but are expected to come into service by 2025, and Existing Renewables are renewables that are currently in service. The "Load" line is the system load without the charging of any energy storage. Any generation above the "Load" line is energy that goes into an energy storage system. Overgeneration is remaining no-cost capacity that does not go into meeting any of the system load or energy storage systems.

As shown in the figures below, in 2029, the new firm renewable generators are needed regardless if it is a high or low renewable day. Also, on low-renewable days, the new firm renewable generators are needed in 2033, even with the large number of renewables added in prior years.

Figure 117. Daily chart – Base_508_Staggered scenario – High-renewable day

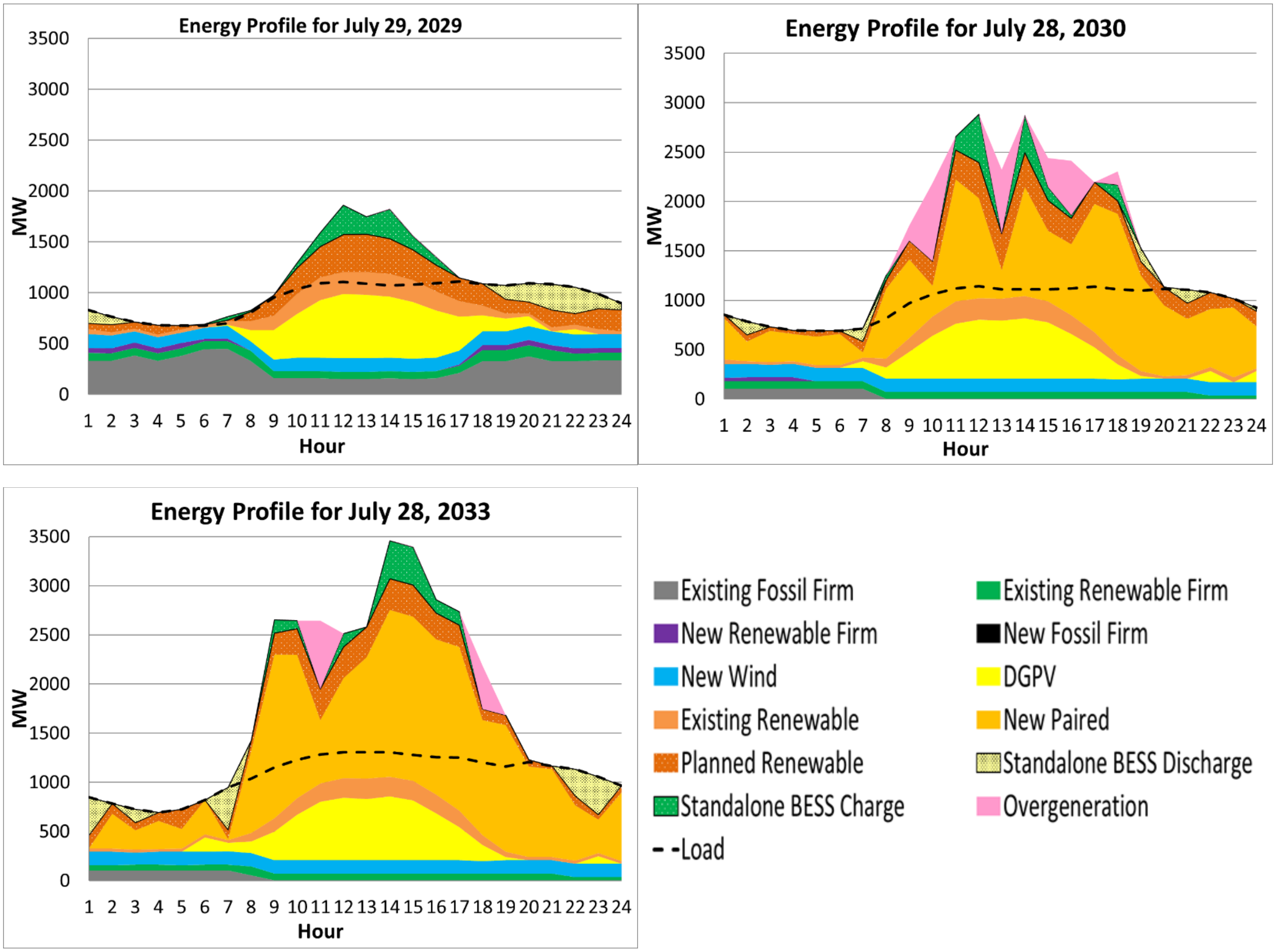
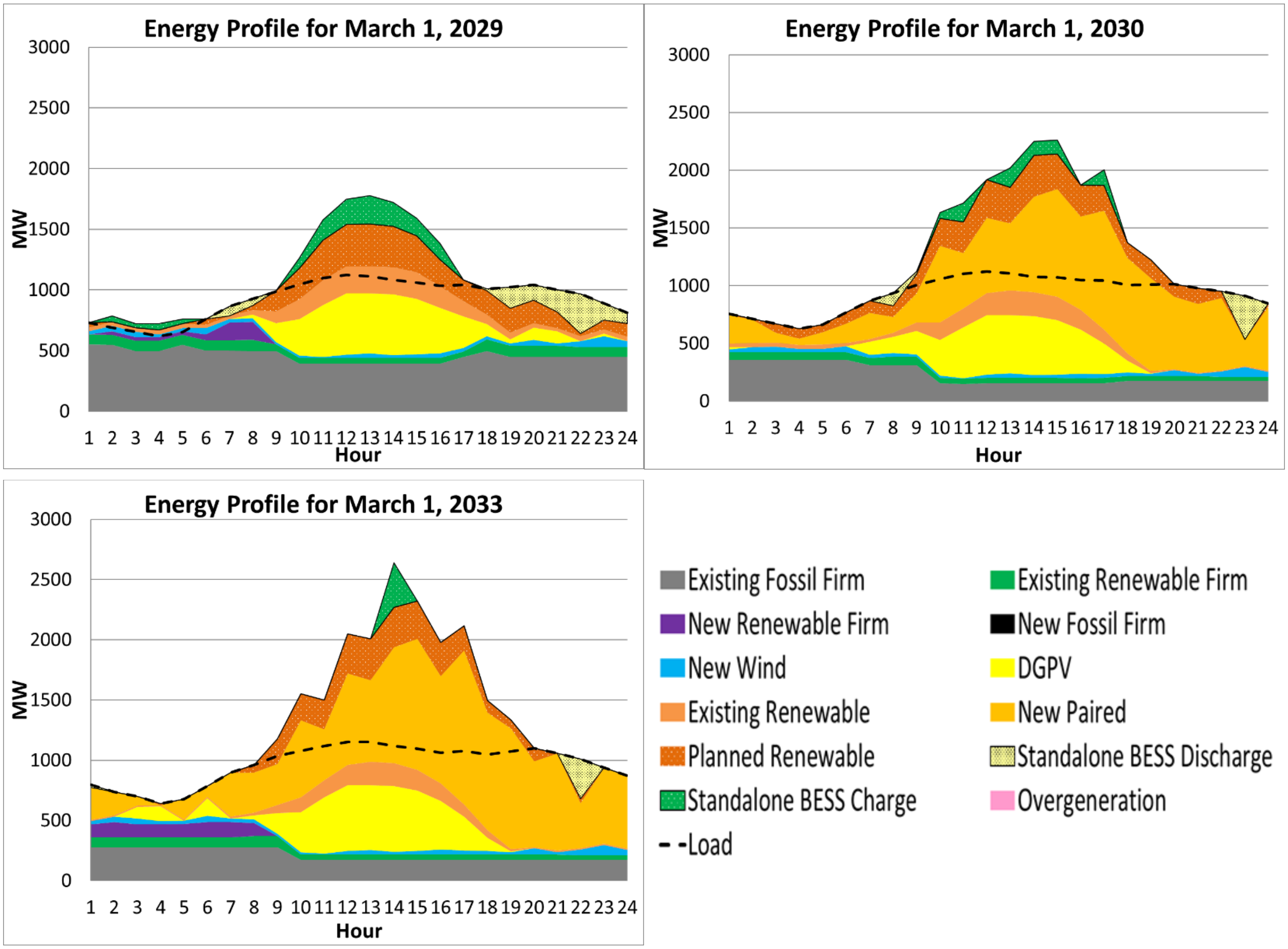


Figure 118. Daily chart – Base_508_Staggered scenario – Low-renewable day



Shown below in Figure 119 is the dispatch for a high-renewable day in 2029, 2030 and 2033 for the Base_508_Staggered_Fossil scenario, where the new firm resource is on fossil-fuel. Shown below in Figure 120 is the dispatch for a low renewable day in 2029, 2030 and 2033 for the Base_508_Staggered_Fossil scenario, where the new firm resource is on fossil-fuel. As shown in the figures below, when the new firm generators are on fossil-fuel, they are expected to operate significantly more than when they are on biofuel. This is driven by the almost 50% reduction in price for diesel when compared to biodiesel. Despite the higher utilization of the new firm resources, there is still a significant amount of variable renewable generation that will be used to serve load.

Figure 119. Daily chart – Base_508_Staggered_Fossil scenario – High-renewable day

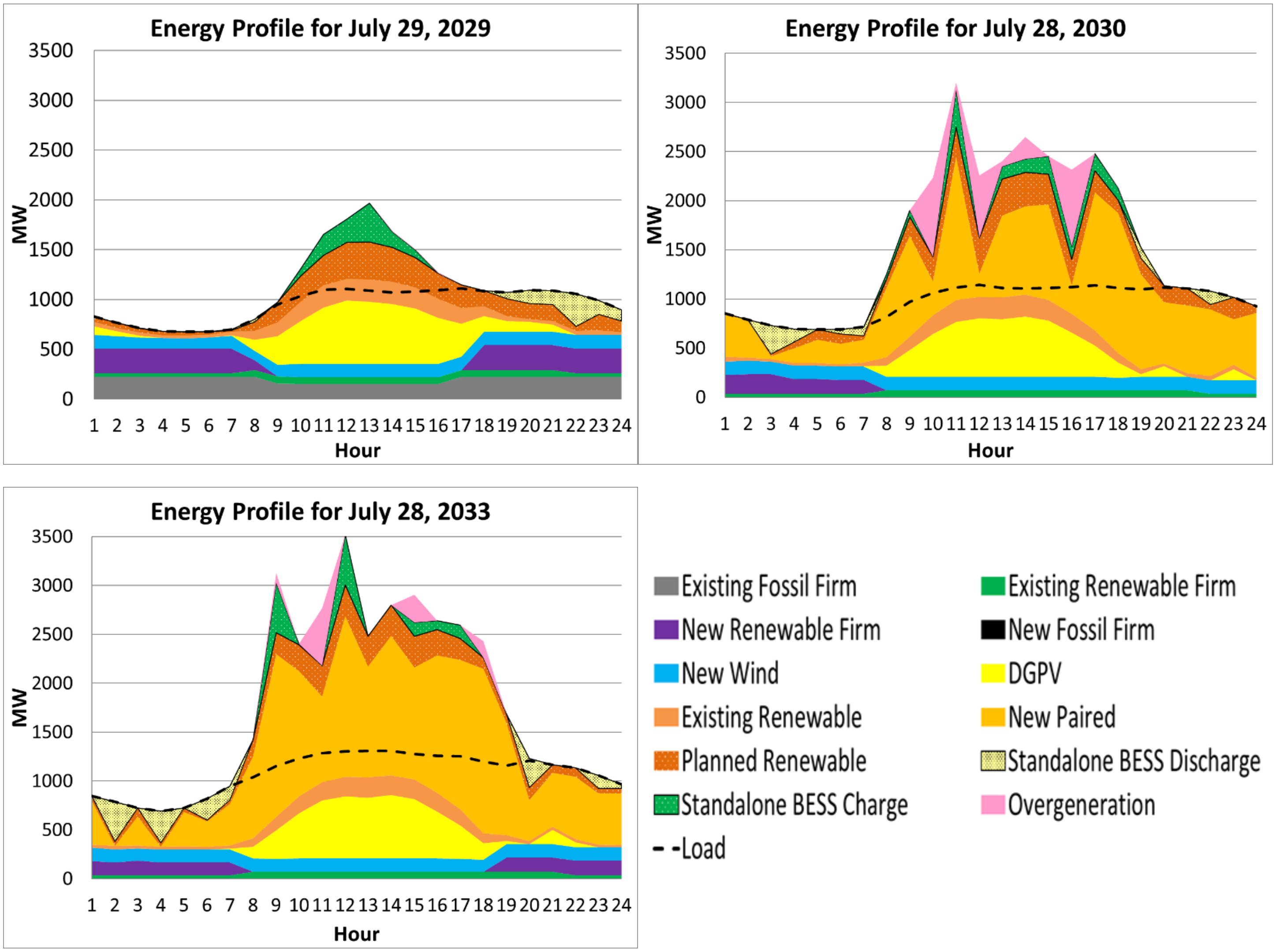
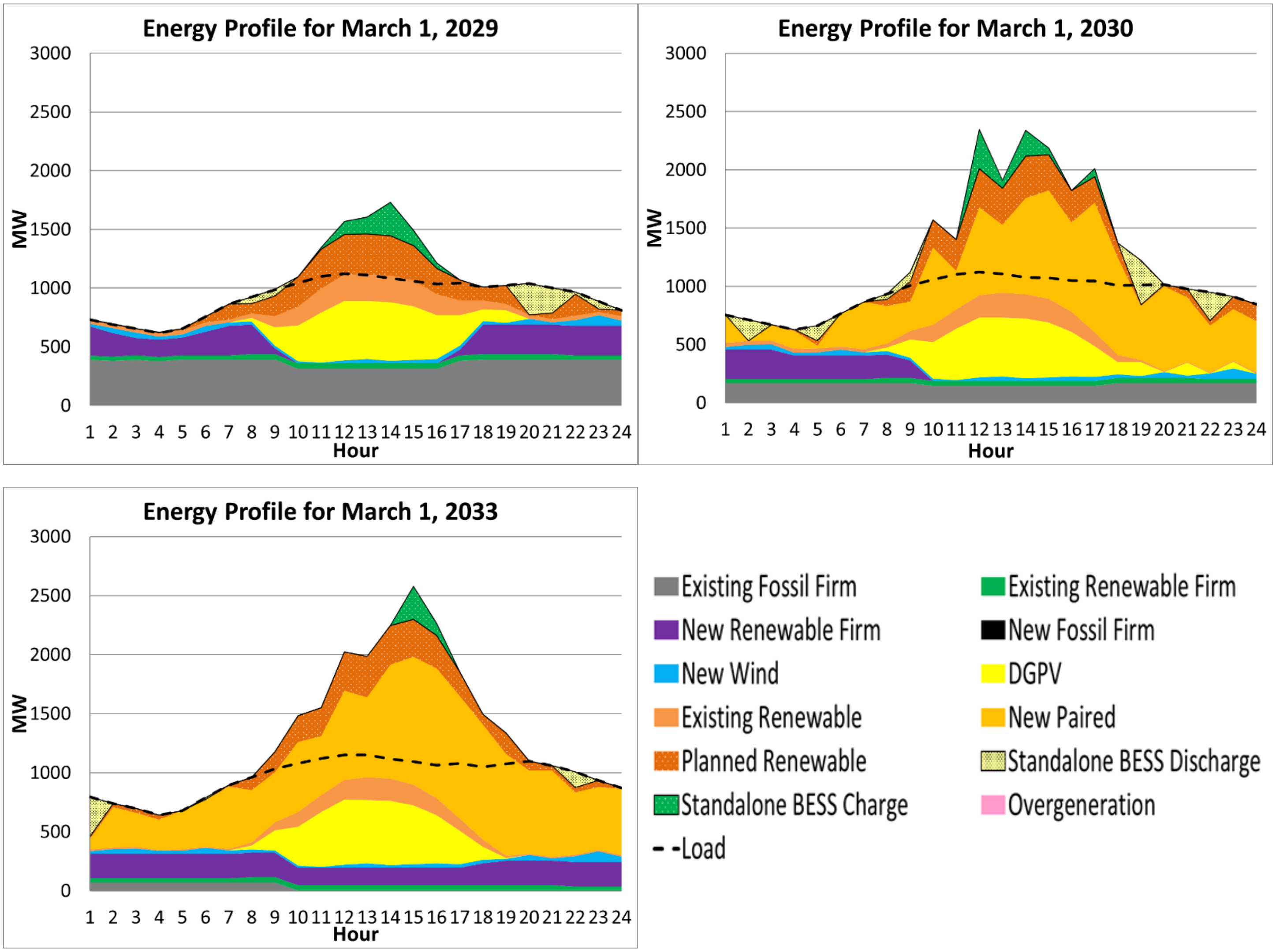


Figure 120. Daily chart – Base_508_Staggered_Fossil scenario – Low-renewable day



7.1.3 Results – RPS-A

Shown below in Figure 121 and Figure 122 is the RPS-A for each of the Base staggered resource plans and Land Constrained staggered resource plans, respectively. The darker columns are the case where the new firm resources were assumed to be on biofuel and the lighter columns are the cases where the new firm resources were assumed to be on fossil-fuel. RPS-A is consistent with the recent amended RPS definition after Governor Ige signed Act 240 (HB2089).

Figure 121. RPS-A for the Base (staggered) scenarios

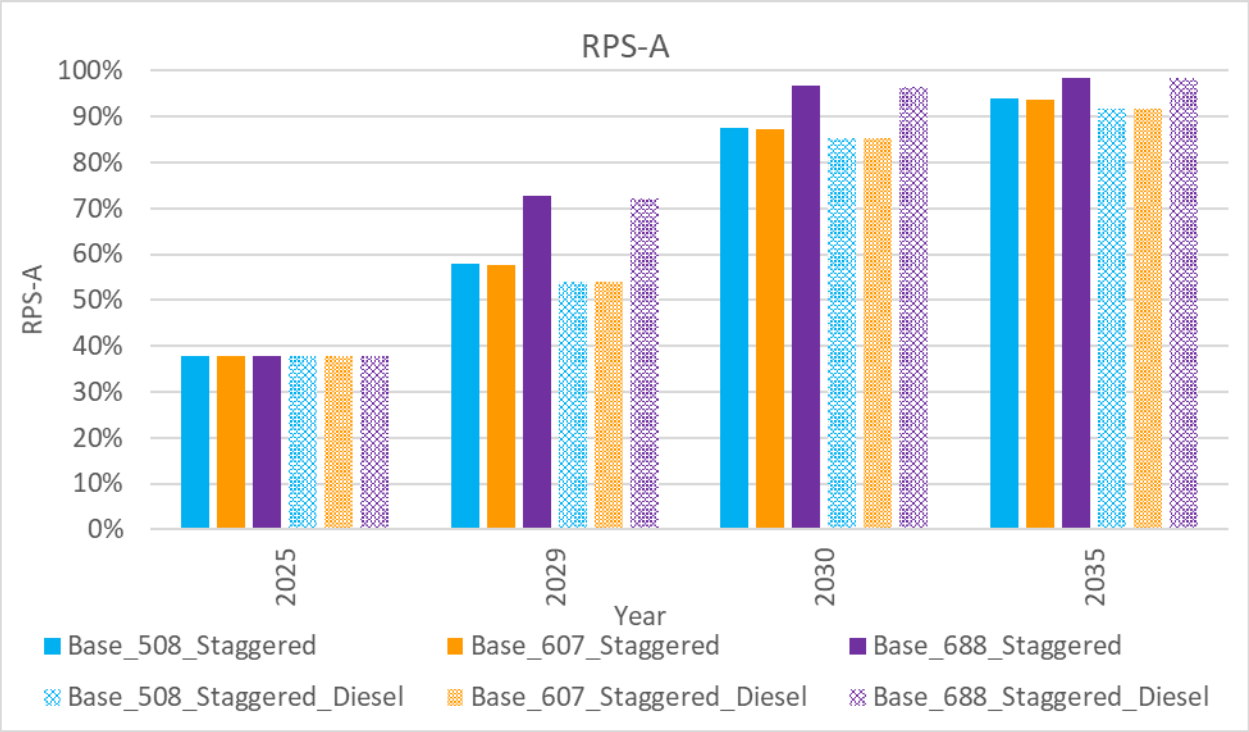
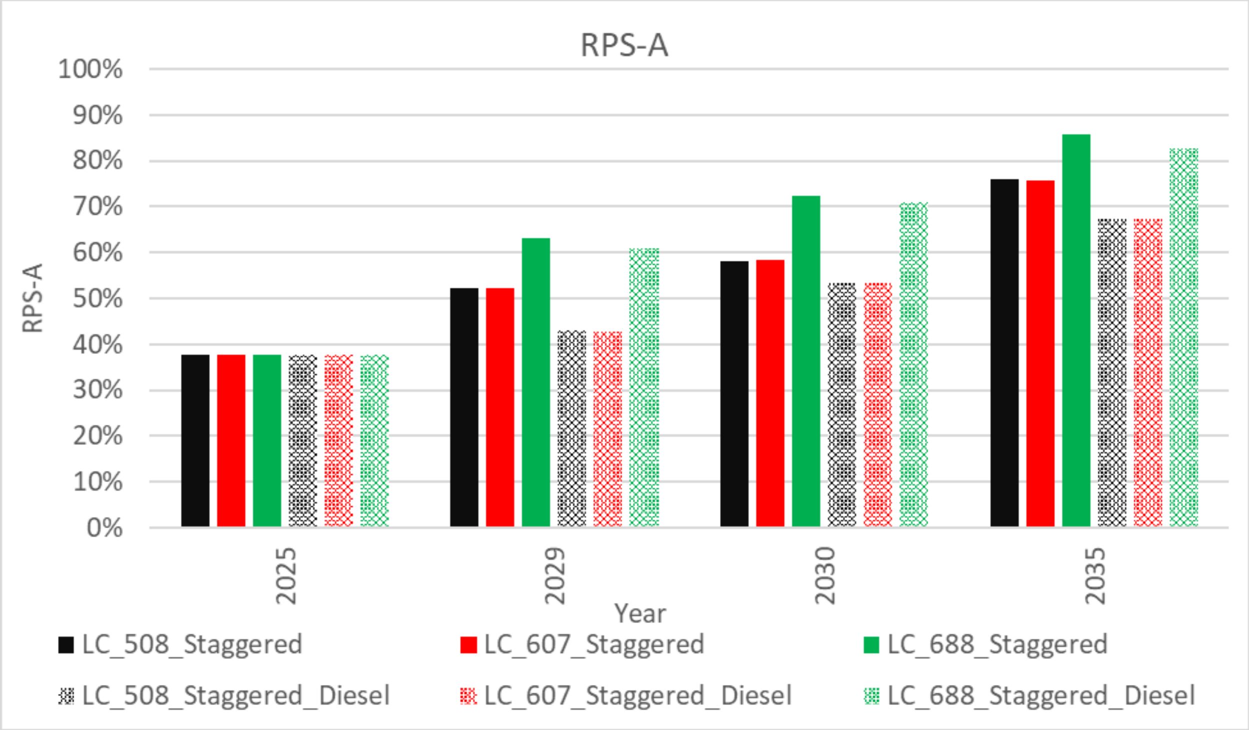


Figure 122. RPS-A for each of the Land Constrained (staggered) scenarios



In the cases where a firm biomass is added, the RPS-A is noticeably higher than the cases where only CT/CC/ICE are added. Also, the Base staggered cases achieve a noticeably higher RPS-A than the Land Constrained staggered cases due to the large amounts of renewables that are added to the system in the Base staggered cases.

7.1.4 Results – Relative NPV

Shown below in Figure 123 is a comparison of the estimated NPV in 2021$ for each of the Base staggered resource plans for 2025-2035 and in Figure 124 is a comparison of the estimated NPV in 2021$ for each of the Land Constrained staggered resource plans for 2025-2035. The cost includes revenue requirements for fuel, variable and fixed O&M, capacity and energy payments for IPP, and capital.

Figure 123. Relative NPV for the Base (staggered) scenarios

	% Difference Relative to Base_508_Staggered (NPV 2025-2035)	NPV 2025-2035 (2021$, '000)
Base_508_Staggered	100%	$8,173,179
Base_607_Staggered	101%	$8,268,483
Base_688_Staggered	100%	$8,145,437
Base_508_Staggered_Fossil	97%	$7,944,130
Base_607_Staggered_Fossil	99%	$8,069,383
Base_688_Staggered_Fossil	99%	$8,101,986

Figure 124. Relative NPV for the Land Constrained (staggered) scenarios

	% Difference Relative to LC_508_Staggered (NPV 2025-2035)	NPV 2025-2035 (2021$, '000)
LC_508_Staggered	100%	$9,156,864
LC_607_Staggered	101%	$9,228,775
LC_688_Staggered	94%	$8,614,233
LC_508_Staggered_Fossil	93%	$8,538,185
LC_607_Staggered_Fossil	94%	$8,583,024
LC_688_Staggered_Fossil	91%	$8,328,604

When the new CT, CC, and ICE are on biofuel, the NPV increases. This occurs because the high cost of biofuel causes low utilization of these resources, and as a result, they are primarily on standby. The addition of biomass, however, causes the NPV to decrease. This is due to the low fuel cost of biomass that was provided in the 2021 NREL Annual Technology Baseline, and as a result, the biomass offsets some of the generation provided by the existing generators on more expensive fossil-fuel.

When the new CT, CC, and ICE are on fossil-fuel, however, the NPV decreases. This occurs because the better efficiency of the new CT, CC, ICE causes greater utilization of these resources, and as a result, their addition offsets some of the generation provided by the existing generators. In the Base case with the large amount of renewable energy already being added, more firm generation added to the system causes the NPV to increase.

8 RECOMMENDED ACTIONS AND NEXT STEPS

Continue to displace fossil-fuel through acquisition of low cost, low carbon renewable energy, starting with 544 GWh through the Stage 3 RFP in Docket No. 2017-0352.

The Grid Needs Assessment provides consistent findings across multiple futures – if renewable energy can be acquired at a low cost, such resources should be pursued in alignment with efforts to reduce carbon emissions by 70% by 2030. The grid needs assessment indicates that 544 GWhs of renewable dispatchable generation in 2027 is needed to offset energy previously provided by the AES coal plant and provide a market test of the remaining, developable renewable potential that can be put into service by 2027.

Continue to pursue customer adoption of DER through new programs and advanced rate design, consistent with the outcomes of the DER Docket No. 2019-0323.

The Grid Needs Assessment demonstrates the necessity of DER to achieve 70% greenhouse gas reductions by 2030, to reduce grid-scale resource needs, and contribute to resource adequacy. Programs and advanced rate designs should provide cost-effective incentives to encourage or accelerate adoptions of these resources.

Pursue generation modernization as soon as practicable to improve operational flexibility and mitigate present reliability risks. Firm renewable generation needs include 300-500 MW of in 2029, and another 200 MW in the 2033 timeframe, starting with the Stage 3 RFP in Docket No. 2017-0352.

The current steam generation fleet on Oʻahu has served the community well beyond its expected life and is now operated as a flexible generator, a role it was not designed for. Thus, in recent years, the availability of those generators continues to decrease, which directly impacts reliability. As recent experience has demonstrated, when resources are needed to fulfill reliability needs on a short timeframe or in emergency situations, options are limited to measures such as customer programs and backup diesel generators. Customer programs, while effective, have shown they take time to ramp up even when significant premiums and incentives are offered, and backup diesel generators may not have long-term grid or environmental value. Reliability analysis completed as part of the grid needs assessment demonstrates that 500-700 MW is a "least regrets" range of firm capacity generation across multiple future scenarios and could allow a significant reduction in dependency on older fossil-fuel generators. New renewable firm generation will also diversify the resource portfolio that is currently heavy with solar and susceptible to severe weather events.

Pursue development of renewable energy zones to facilitate interconnection of additional renewable energy.

The grid needs assessment found that partial or full buildout of certain renewable energy zones could be cost-effective if paired with low-cost renewable energy resources. Renewable energy zones will be needed to maintain transmission reliability, harvest solar and wind resources and transmit them to the load center. Community and commercial interests should be engaged to determine the viability of enabling renewable energy zones for timely development as part of the next competitive procurement for renewable energy following the expected Stage 3 RFP.

Consider procurement of energy efficiency to accelerate adoption in amounts up to the forecasted target to reduce supply side needs.

Significant energy efficiency is forecasted over the next 10 years. Aggressive acquisition of cost-effective energy efficiency measures, greater than what has been acquired historically, should be pursued to reduce supply-side needs and add diversity to the resource portfolio. A procurement of EE from energy service providers could potentially accelerate adoption in parallel to on-going programmatic efforts.

Continue to pursue managed EV charging programs, time-of-use rates, DER, and energy efficiency.

Continued pursuit of flexible management of customer resources, building upon programs such as battery bonus, grid services agreements with aggregators, electric bus time-of-use rates and residential and commercial time-of-use rates. Efforts should continue to attract customer participation to adopt technologies that can support grid management balanced with the cost of operating the grid and the allocation of those costs.

Incorporate system security and system stability analyses, which may yield additional resource needs to mitigate risks associated with a high renewable energy system.

The next iteration of the O‘ahu Grid Needs Assessment will include system security analysis within the IGP process. System security will be critical to realizing a decarbonized grid to ensure that the appropriate essential reliability services are in place to operate a system dominated by inverter-based resources (solar, wind, battery energy storage). The output from the system security study analysis will confirm whether the system under future expansion has any transmission planning criteria violation(s). Violations can be steady state (e.g., steady state voltage, equipment thermal loading, steady state voltage stability, and voltage and current harmonics) or dynamic stability (e.g., excessive under frequency load shedding, undamped oscillation), and may be identified as temporary in nature (e.g., only exists under extreme dispatch scenario) or permanent (e.g., could happen every day).

System security measures include, but are not limited to, proven grid-forming inverters, improving legacy and first-generation advanced inverter trip-and ride-through settings, including EV batteries. These measures will support and improve system stability, synchronous condensers and improved underfrequency load shedding. Example mitigations are provided in the table below.

Examples of Mitigation Solutions Required by System Security Analysis
• Install traditional wire solutions (e.g. reconductor, cable replacement, add transformers to increase steady state capacity, add cap banks)
• Add synchronous condensers, STATCOM to address dynamic voltage support and increase short circuit current
• Short duration, temporary curtailment of a non-GFM resource
• Short duration, temporary charge of grid-scale GFM BESS and increase rotating machine generation
• Short duration, temporary increase in generation at certain locations to provide voltage support
• Install additional centralized FFR resource
• Reserve headroom on GFM resource
• Increase number of inverter units to increase IBR short circuit capacity, overcurrent capacity
• Retrofit a GFL resource to enable GFM function (currently only for the resources with BESS, future could be for standalone PV and wind)
• Retrofit DER inverter ride-through settings
• Revise Rule 14H source requirements document
• Add additional communication and control to increase capacity of controllable DER
• Add GFM STATCOM to address system stability issue
• Add dual-pilot communication to enable fast protection
• Increase circuit breaker size to host more firm generation
• Use dynamic UFLS to improve UFLS effectiveness
• Use advanced protection to address high inverter penetration system protection issue
• Add power quality filter to mitigate power quality issue
• Add individual equipment (e.g., BESS) to provide damping for system oscillation

Pursue procurement(s) as part of the IGP solution sourcing process to determine market for long lead renewable resources such as offshore wind and renewable energy zones to increase resource diversity and mitigate land use risks.

The various futures are consistent in maximizing grid-scale hybrid solar due to its cost-effective energy; however, there are many uncertainties concerning the amount of hybrid solar that will be built over the near-term including, community needs, land availability, slope of the land and willingness of landowners to participate, among others. If high amounts of solar cannot be built in the near-term, other low-carbon resources will be needed. The land constrained scenario suggests that resources that take more than 5 years to develop such as offshore wind will be critical to achieving decarbonization goals. A more diverse portfolio will also improve the resilience of the resource portfolio.

9 APPENDIX

9.1 Capacity Expansion Plans

Figure 125. Resource plans for the High Load and Low Load cases

Year	RESOLVE – High Load	RESOLVE – Low Load
Stage 1 and 2 Projects	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar Mahi Solar Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar Mahi Solar Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage
2027	Install 82MW of Group 1 Onshore Wind Install 82MW of Group 2 Onshore Wind Install 3MW 5 MWh of Standalone BESS Remove 108 MW of Firm Generation	Install 82MW of Group 1 Onshore Wind Install 82MW of Group 2 Onshore Wind Install 286MW 537MWH of Standalone Battery Remove 108 MW Firm Generation
2028	Install 47MW of LM6000_2x1CC_SyncCond Install 17MW 32 MWh of Standalone BESS	Install 20MW 37MWH of Standalone Battery
2029	Install 134MW 134 MWh of Group 1 Paired PV Install 170MW of LM6000_2x1CC_SyncCond Install 32MW of LM6000CT Install 83MW 160 MWh of Standalone BESS Remove 165 MW of Firm Generation	Install 18MW 33MWH of Standalone Battery Remove 165 MW of Firm Generation
2030	Install 295MW 1060 MWh of Group 1 Paired PV Install 1249MW 3212 MWh of Group 2 Paired PV Install 2MW 0 MWh of Standalone BESS	Install 428MW of Group 1 Paired PV 1500 MWh Install 861MW of Group 2 Paired PV 2346 MWh Install 108MW 203MWH of Standalone Battery
2031	Install 0MW 124 MWh of Group 1 Paired PV Install 195MW 718 MWh of Group 2 Paired PV Remove 30 MW Kahuku Wind	Install 71MW of Group 2 Paired PV 263 MWh Remove 30 MW Kahuku Wind
2032	Install 0MW 157 MWh of Group 1 Paired PV Install 54MW 247 MWh of Group 2 Paired PV Install 125MW 335 MWh of Group 3 Paired PV Remove 1 MW Kapolei Sustainable Energy Park	Install 60MW of Group 2 Paired PV 162 MWh Remove 1 MW Kapolei Sustainable Energy Park
2033	Install 0MW 84 MWh of Group 1 Paired PV Install 0MW 66 MWh of Group 2 Paired PV Install 168MW 516 MWh of Group 3 Paired PV Install 0MW 1 MWh of Standalone BESS Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 7MW of Group 2 Paired PV 0 MWh Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II
2034	Install 20MW 135 MWh of Group 2 Paired PV Install 114MW 343 MWh of Group 3 Paired PV Install 33MW of LM6000CT Remove 5 MW Kalaeloa Renewable Energy Park	Install 5MW of Group 2 Paired PV 0 MWh Remove 5 MW Kalaeloa Renewable Energy Park

Year	RESOLVE – High Load	RESOLVE – Low Load
2035	Install 204MW of Offshore Wind Install 73MW of LM6000CT	Install 10MW of Group 2 Paired PV 0 MWh Install 44MW of Offshore Wind Install 10MW of LM6000CT
2036		
2037	Remove 171 MW of Firm Generation	Remove 171 MW of Firm Generation
2038	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind
2039	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar
2040	Install 2MW 129 MWh of Group 2 Paired PV Install 588MW 1765 MWh of Group 3 Paired PV Install 152MW of Biomass Install 88MW of LM6000CT	Install 398MW of Group 2 Paired PV 1094 MWh Install 111MW of Group 3 Paired PV 259 MWh Install 37MW of Biomass Install 130MW of LM6000CT
2041	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects
2042		
2043		
2044	Remove 20 MW of West Loch	Remove 20 MW of West Loch
2045	Install 73MW 0 MWh of Group 2 Paired PV Install 171MW 153 MWh of Group 3 Paired PV Install 192MW of Biomass Install 59MW 111 MWh of Standalone BESS	Install 126MW of Group 2 Paired PV 0 MWh Install 551MW of Group 3 Paired PV 1297 MWh Install 66MW of Biomass
2046	Remove 269 MW of Firm Generation	Remove 269 MW of Firm Generation
2047		
2048		
2049		
2050	Install 89MW of Biomass	Install 53MW of Group 2 Paired PV 190 MWh Install 182MW of Group 3 Paired PV 212 MWh Install 76MW of Biomass Install 223MW of LM6000CT

Figure 126. Resource plans for the Base case and the Land Constrained case

Year	RESOLVE - Base	RESOLVE - Land Constrained
Stage 1 and 2 Projects	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar Mahi Solar Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar Mahi Solar Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage
2027	Install 82MW of Group 1 Onshore Wind Install 82MW of Group 2 Onshore Wind Install 231MW 434MWH of Standalone Battery Remove 108 MW of Firm Generation	Install 176MW 331 MWh of Standalone BESS Remove 108 MW of Firm Generation
2028	Install 14MW 26MWH of Standalone Battery	Install 14MW 25 MWh of Standalone BESS
2029	Install 35MW of LM6000_2x1CC_SyncCond Install 42MW 79MWH of Standalone Battery Remove 165 MW of Firm Generation	Install 39MW of LM6000_2x1CC_SyncCond Install 43MW 81 MWh of Standalone BESS Remove 165 MW of Firm Generation
2030	Install 428MW of Group 1 Paired PV 1489 MWh Install 1148MW of Group 2 Paired PV 2973 MWh Install 93MW 174MWH of Standalone Battery	Install 270MW 270 MWh of Group 1 Paired PV Install 88MW 162 MWh of Standalone BESS
2031	Install 0MW of Group 1 Paired PV 74 MWh Install 107MW of Group 2 Paired PV 423 MWh Install 8MW 14MWH of Standalone Battery Remove 30 MW Kahuku Wind	Remove 30 MW Kahuku Wind
2032	Install 0MW of Group 1 Paired PV 68 MWh Install 62MW of Group 2 Paired PV 211 MWh Remove 1 MW Kapolei Sustainable Energy Park	Install 4MW 7 MWh of Standalone BESS Remove 1 MW Kapolei Sustainable Energy Park
2033	Install 0MW of Group 1 Paired PV 19 MWh Install 90MW of Group 2 Paired PV 328 MWh Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 172MW of LM6000_2x1CC_SyncCond Install 0MW 1 MWh of Standalone BESS Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II
2034	Install 101MW of Group 2 Paired PV 321 MWh Install 8MW of LM6000_2x1CC_SyncCond Remove 5 MW Kalaeloa Renewable Energy Park	Install 31MW of LM6000_2x1CC_SyncCond Install 18MW 33 MWh of Standalone BESS Remove 5 MW Kalaeloa Renewable Energy Park
2035	Install 78MW of Offshore Wind Install 6MW of LM6000_2x1CC_SyncCond Install 19MW of LM6000CT	Install 400MW of Offshore Wind Install 22MW of LM6000_2x1CC_SyncCond Install 86MW 162 MWh of Standalone BESS

Year	RESOLVE - Base	RESOLVE - Land Constrained
2036		
2037	Remove 171 MW of Firm Generation	Remove 171 MW of firm generation
2038	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind
2039	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar
2040	Install 58MW of Group 2 Paired PV 317 MWh Install 628MW of Group 3 Paired PV 1573 MWh Install 6MW of Biomass Install 177MW of LM6000CT	Install 68MW of Aggregated DER 136 MWh Install 154MW of LM6000_2x1CC_SyncCond Install 90MW of LM6000CT Install 23MW 45 MWh of Standalone BESS
2041	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects
2042		
2043		
2044	Remove 20 MW of West Loch	Remove 20 MW of West Loch
2045	Install 26MW of Group 2 Paired PV 0 MWh Install 538MW of Group 3 Paired PV 1291 MWh Install 115MW of Biomass Install 7MW 13MWH of Standalone Battery	Install 0MW 933 MWh of Group 1 Paired PV Install 1706MW of Aggregated DER 3412 MWh Install 388MW 2695 MWh of Standalone BESS
2046	Remove 269 MW Firm Generation	Remove 269 MW Firm Generation
2047		
2048		
2049		
2050	Install 0MW of Group 3 Paired PV 223 MWh Install 132MW of Biomass Install 192MW of LM6000CT Install 23MW 51MWH of Standalone Battery	Install 0MW 76 MWh of Group 1 Paired PV Install 961MW of Aggregated DER 1923 MWh Install 185MW of LM6000CT Install 78MW 761 MWh of Standalone BESS

Figure 127. Resource plans for the Base_508, Base_607 and Base_688 scenarios

Year	Base_508	Base_607	Base_688
Stage 1 and 2 Projects	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage
2027	Install 82MW of Group 1 Onshore Wind Install 82MW of Group 2 Onshore Wind Install 231MW 434MWH of Standalone Battery Remove 108 MW Firm Generation	Install 82MW of Group 1 Onshore Wind Install 82MW of Group 2 Onshore Wind Install 231MW 434MWH of Standalone Battery Remove 108 MW Firm Generation	Install 82MW of Group 1 Onshore Wind Install 82MW of Group 2 Onshore Wind Install 231MW 434MWH of Standalone Battery Remove 108 MW Firm Generation
2028	Install 14MW 26MWH of Standalone Battery	Install 14MW 26MWH of Standalone Battery	Install 14MW 26MWH of Standalone Battery
2029	Install 42MW 79MWH of Standalone Battery Install 300 MW CT Install 208 MW CC Remove 165 MW Firm Generation Remove 208 MW KPLP	Install 42MW 79MWH of Standalone Battery Install 300 MW CT Install 208 MW CC Install 99 MW ICE Remove 165 MW Firm Generation Remove 208 MW KPLP	Install 42MW 79MWH of Standalone Battery Install 300 MW CT Install 208 MW CC Install 180 MW Biomass Remove 165 MW Firm Generation Remove 208 MW KPLP
2030	Install 428MW of Group 1 Paired PV 1489 MWh Install 1148MW of Group 2 Paired PV 2973 MWh Install 93MW 174MWH of Standalone Battery	Install 428MW of Group 1 Paired PV 1489 MWh Install 1148MW of Group 2 Paired PV 2973 MWh Install 93MW 174MWH of Standalone Battery	Install 428MW of Group 1 Paired PV 1489 MWh Install 1148MW of Group 2 Paired PV 2973 MWh Install 93MW 174MWH of Standalone Battery
2031	Install 0MW of Group 1 Paired PV 74 MWh Install 107MW of Group 2 Paired PV 423 MWh Install 8MW 14MWH of Standalone Battery Remove 30 MW Kahuku Wind	Install 0MW of Group 1 Paired PV 74 MWh Install 107MW of Group 2 Paired PV 423 MWh Install 8MW 14MWH of Standalone Battery Remove 30 MW Kahuku Wind	Install 0MW of Group 1 Paired PV 74 MWh Install 107MW of Group 2 Paired PV 423 MWh Install 8MW 14MWH of Standalone Battery Remove 30 MW Kahuku Wind
2032	Install 0MW of Group 1 Paired PV 68 MWh Install 62MW of Group 2 Paired PV 211 MWh Remove 1 MW Kapolei Sustainable Energy Park	Install 0MW of Group 1 Paired PV 68 MWh Install 62MW of Group 2 Paired PV 211 MWh Remove 1 MW Kapolei Sustainable Energy Park	Install 0MW of Group 1 Paired PV 68 MWh Install 62MW of Group 2 Paired PV 211 MWh Remove 1 MW Kapolei Sustainable Energy Park

Year	Base_508	Base_607	Base_688
2033	Install 0MW of Group 1 Paired PV 19 MWh Install 90MW of Group 2 Paired PV 328 MWh Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 0MW of Group 1 Paired PV 19 MWh Install 90MW of Group 2 Paired PV 328 MWh Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 0MW of Group 1 Paired PV 19 MWh Install 90MW of Group 2 Paired PV 328 MWh Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II
2034	Install 101MW of Group 2 Paired PV 321 MWh Remove 5 MW Kalaeloa Renewable Energy Park	Install 101MW of Group 2 Paired PV 321 MWh Remove 5 MW Kalaeloa Renewable Energy Park	Install 101MW of Group 2 Paired PV 321 MWh Remove 5 MW Kalaeloa Renewable Energy Park
2035	Install 78MW of Offshore Wind	Install 78MW of Offshore Wind	Install 78MW of Offshore Wind
2036			
2037	Remove 171 MW of Firm Generation	Remove 171 MW of Firm Generation	Remove 171 MW of Firm Generation
2038	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind
2039	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar
2040	Install 58MW of Group 2 Paired PV 317 MWh Install 628MW of Group 3 Paired PV 1573 MWh	Install 58MW of Group 2 Paired PV 317 MWh Install 628MW of Group 3 Paired PV 1573 MWh	Install 58MW of Group 2 Paired PV 317 MWh Install 628MW of Group 3 Paired PV 1573 MWh
2041	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects
2042			
2043			
2044	Remove 20 MW of West Loch	Remove 20 MW of West Loch	Remove 20 MW of West Loch
2045	Install 26MW of Group 2 Paired PV 0 MWh Install 538MW of Group 3 Paired PV 1291 MWh Install 7MW 13MWH of Standalone Battery	Install 26MW of Group 2 Paired PV 0 MWh Install 538MW of Group 3 Paired PV 1291 MWh Install 7MW 13MWH of Standalone Battery	Install 26MW of Group 2 Paired PV 0 MWh Install 538MW of Group 3 Paired PV 1291 MWh Install 7MW 13MWH of Standalone Battery
2046	Remove 269 MW Firm Generation	Remove 269 MW Firm Generation	Remove 269 MW Firm Generation
2047			
2048			
2049			
2050	Install 0MW of Group 3 Paired PV 223 MWH Install 23MW 51MWH of Standalone Battery	Install 0MW of Group 3 Paired PV 223 MWH Install 23MW 51MWH of Standalone Battery	Install 0MW of Group 3 Paired PV 223 MWH Install 23MW 51MWH of Standalone Battery

Figure 128. Resource plans for the LC_508, LC_607 and LC_688 scenarios

Year	LC_508	LC_607	LC_688
Stage 1 and 2 Projects	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O’ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O’ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O’ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage
2027	Install 176MW 331 MWh of Standalone BESS Remove 108 MW of Firm Generation	Install 176MW 331 MWh of Standalone BESS Remove 108 MW of Firm Generation	Install 176MW 331 MWh of Standalone BESS Remove 108 MW of Firm Generation
2028	Install 14MW 25 MWh of Standalone BESS	Install 14MW 25 MWh of Standalone BESS	Install 14MW 25 MWh of Standalone BESS
2029	Install 43MW 81 MWh of Standalone BESS Install 300 MW CT Install 208 MW CC Remove 165 MW of Firm Generation Remove 208 MW KPLP	Install 43MW 81 MWh of Standalone BESS Install 300 MW CT Install 208 MW CC Install 99 MW ICE Remove 165 MW of Firm Generation Remove 208 MW KPLP	Install 43MW 81 MWh of Standalone BESS Install 300 MW CT Install 208 MW CC Install 180 MW Biomass Remove 165 MW of Firm Generation Remove 208 MW KPLP
2030	Install 270MW 270 MWh of Group 1 Paired PV Install 88MW 162 MWh of Standalone BESS **Install 120 MW 480 MWh of Mahi Solar** **Install 60 MW 240 MWh of Kupehau**	Install 270MW 270 MWh of Group 1 Paired PV Install 88MW 162 MWh of Standalone BESS **Install 120 MW 480 MWh of Mahi Solar** **Install 60 MW 240 MWh of Kupehau**	Install 270MW 270 MWh of Group 1 Paired PV Install 88MW 162 MWh of Standalone BESS **Install 120 MW 480 MWh of Mahi Solar** **Install 60 MW 240 MWh of Kupehau**
2031	Remove 30 MW Kahuku Wind	Remove 30 MW Kahuku Wind	Remove 30 MW Kahuku Wind
2032	Install 4MW 7 MWh of Standalone BESS Remove 1 MW Kapolei Sustainable Energy Park	Install 4MW 7 MWh of Standalone BESS Remove 1 MW Kapolei Sustainable Energy Park	Install 4MW 7 MWh of Standalone BESS Remove 1 MW Kapolei Sustainable Energy Park
2033	Install 0MW 1 MWh of Standalone BESS Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 0MW 1 MWh of Standalone BESS Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 0MW 1 MWh of Standalone BESS Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II
2034	Install 18MW 33 MWh of Standalone BESS Remove 5 MW Kalaeloa Renewable Energy Park	Install 18MW 33 MWh of Standalone BESS Remove 5 MW Kalaeloa Renewable Energy Park	Install 18MW 33 MWh of Standalone BESS Remove 5 MW Kalaeloa Renewable Energy Park

Year	LC_508	LC_607	LC_688
2035	Install 400MW of Offshore Wind Install 86MW 162 MWh of Standalone BESS	Install 400MW of Offshore Wind Install 86MW 162 MWh of Standalone BESS	Install 400MW of Offshore Wind Install 86MW 162 MWh of Standalone BESS
2036			
2037	Remove 171 MW of Firm Generation	Remove 171 MW of Firm Generation	Remove 171 MW of Firm Generation
2038	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind
2039	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar
2040	Install 68MW of Aggregated DER 136 MWh Install 23MW 45 MWh of Standalone BESS	Install 68MW of Aggregated DER 136 MWh Install 23MW 45 MWh of Standalone BESS	Install 68MW of Aggregated DER 136 MWh Install 23MW 45 MWh of Standalone BESS
2041	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects
2042			
2043			
2044	Remove 20 MW of West Loch	Remove 20 MW of West Loch	Remove 20 MW of West Loch
2045	Install 0MW 933 MWh of Group 1 Paired PV Install 1706MW of Aggregated DER 3412 MWh Install 388MW 2695 MWh of Standalone BESS	Install 0MW 933 MWh of Group 1 Paired PV Install 1706MW of Aggregated DER 3412 MWh Install 388MW 2695 MWh of Standalone BESS	Install 0MW 933 MWh of Group 1 Paired PV Install 1706MW of Aggregated DER 3412 MWh Install 388MW 2695 MWh of Standalone BESS
2046	Remove 269 MW of Firm Generation	Remove 269 MW of Firm Generation	Remove 269 MW of Firm Generation
2047			
2048			
2049			
2050	Install 0MW 76 MWh of Group 1 Paired PV Install 961MW of Aggregated DER 1923 MWh Install 78MW 761 MWh of Standalone BESS	Install 0MW 76 MWh of Group 1 Paired PV Install 961MW of Aggregated DER 1923 MWh Install 78MW 761 MWh of Standalone BESS	Install 0MW 76 MWh of Group 1 Paired PV Install 961MW of Aggregated DER 1923 MWh Install 78MW 761 MWh of Standalone BESS

Figure 129. Resource plans for the Base_508_Staggered, Base_607_Staggered and Base_688_Staggered scenarios

Year	Base_508_Staggered	Base_607_Staggered	Base_688_Staggered
Stage 1 and 2 Projects	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage
2027	Install 82MW of Group 1 Onshore Wind Install 82MW of Group 2 Onshore Wind Install 231MW 434MWH of Standalone Battery Remove 108 MW Firm Generation	Install 82MW of Group 1 Onshore Wind Install 82MW of Group 2 Onshore Wind Install 231MW 434MWH of Standalone Battery Remove 108 MW Firm Generation	Install 82MW of Group 1 Onshore Wind Install 82MW of Group 2 Onshore Wind Install 231MW 434MWH of Standalone Battery Remove 108 MW Firm Generation
2028	Install 14MW 26MWH of Standalone Battery	Install 14MW 26MWH of Standalone Battery	Install 14MW 26MWH of Standalone Battery
2029	Install 42MW 79MWH of Standalone Battery Install 300 MW CT Remove 165 MW Firm Generation Remove 208 MW KPLP	Install 42MW 79MWH of Standalone Battery Install 300 MW CT Install 99 MW ICE Remove 165 MW Firm Generation Remove 208 MW KPLP	Install 42MW 79MWH of Standalone Battery Install 300 MW CT Install 180 MW Biomass Remove 165 MW Firm Generation Remove 208 MW KPLP
2030	Install 428MW of Group 1 Paired PV 1489 MWh Install 1148MW of Group 2 Paired PV 2973 MWh Install 93MW 174MWH of Standalone Battery	Install 428MW of Group 1 Paired PV 1489 MWh Install 1148MW of Group 2 Paired PV 2973 MWh Install 93MW 174MWH of Standalone Battery	Install 428MW of Group 1 Paired PV 1489 MWh Install 1148MW of Group 2 Paired PV 2973 MWh Install 93MW 174MWH of Standalone Battery
2031	Install 0MW of Group 1 Paired PV 74 MWh Install 107MW of Group 2 Paired PV 423 MWh Install 8MW 14MWH of Standalone Battery Remove 30 MW Kahuku Wind	Install 0MW of Group 1 Paired PV 74 MWh Install 107MW of Group 2 Paired PV 423 MWh Install 8MW 14MWH of Standalone Battery Remove 30 MW Kahuku Wind	Install 0MW of Group 1 Paired PV 74 MWh Install 107MW of Group 2 Paired PV 423 MWh Install 8MW 14MWH of Standalone Battery Remove 30 MW Kahuku Wind
2032	Install 0MW of Group 1 Paired PV 68 MWh Install 62MW of Group 2 Paired PV 211 MWh Remove 1 MW Kapolei Sustainable Energy Park	Install 0MW of Group 1 Paired PV 68 MWh Install 62MW of Group 2 Paired PV 211 MWh Remove 1 MW Kapolei Sustainable Energy Park	Install 0MW of Group 1 Paired PV 68 MWh Install 62MW of Group 2 Paired PV 211 MWh Remove 1 MW Kapolei Sustainable Energy Park

Year	Base_508_Staggered	Base_607_Staggered	Base_688_Staggered
2033	Install 0MW of Group 1 Paired PV 19 MWh Install 90MW of Group 2 Paired PV 328 MWh Install 208 MW CC Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 0MW of Group 1 Paired PV 19 MWh Install 90MW of Group 2 Paired PV 328 MWh Install 208 MW CC Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 0MW of Group 1 Paired PV 19 MWh Install 90MW of Group 2 Paired PV 328 MWh Install 208 MW CC Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II
2034	Install 101MW of Group 2 Paired PV 321 MWh Remove 5 MW Kalaeloa Renewable Energy Park	Install 101MW of Group 2 Paired PV 321 MWh Remove 5 MW Kalaeloa Renewable Energy Park	Install 101MW of Group 2 Paired PV 321 MWh Remove 5 MW Kalaeloa Renewable Energy Park
2035	Install 78MW of Offshore Wind	Install 78MW of Offshore Wind	Install 78MW of Offshore Wind
2036			
2037	Remove 171 MW of Firm Generation	Remove 171 MW of Firm Generation	Remove 171 MW of Firm Generation
2038	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind
2039	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar
2040	Install 58MW of Group 2 Paired PV 317 MWh Install 628MW of Group 3 Paired PV 1573 MWh	Install 58MW of Group 2 Paired PV 317 MWh Install 628MW of Group 3 Paired PV 1573 MWh	Install 58MW of Group 2 Paired PV 317 MWh Install 628MW of Group 3 Paired PV 1573 MWh
2041	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects
2042			
2043			
2044	Remove 20 MW of West Loch	Remove 20 MW of West Loch	Remove 20 MW of West Loch
2045	Install 26MW of Group 2 Paired PV 0 MWh Install 538MW of Group 3 Paired PV 1291 MWh Install 7MW 13MWH of Standalone Battery	Install 26MW of Group 2 Paired PV 0 MWh Install 538MW of Group 3 Paired PV 1291 MWh Install 7MW 13MWH of Standalone Battery	Install 26MW of Group 2 Paired PV 0 MWh Install 538MW of Group 3 Paired PV 1291 MWh Install 7MW 13MWH of Standalone Battery
2046	Remove 269 MW Firm Generation	Remove 269 MW Firm Generation	Remove 269 MW Firm Generation
2047			
2048			
2049			
2050	Install 0MW of Group 3 Paired PV 223 MWH Install 23MW 51MWH of Standalone Battery	Install 0MW of Group 3 Paired PV 223 MWH Install 23MW 51MWH of Standalone Battery	Install 0MW of Group 3 Paired PV 223 MWH Install 23MW 51MWH of Standalone Battery

Figure 130. Resource plans for the LC_508_Staggered, LC_607_Staggered and LC_688_Staggered scenarios

Year	LC_508_Staggered	LC_607_Staggered	LC_688_Staggered
Stage 1 and 2 Projects	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage
2027	Install 176MW 331 MWh of Standalone BESS Remove 108 MW of Firm Generation	Install 176MW 331 MWh of Standalone BESS Remove 108 MW of Firm Generation	Install 176MW 331 MWh of Standalone BESS Remove 108 MW of Firm Generation
2028	Install 14MW 25 MWh of Standalone BESS	Install 14MW 25 MWh of Standalone BESS	Install 14MW 25 MWh of Standalone BESS
2029	Install 43MW 81 MWh of Standalone BESS Install 300 MW CT Remove 165 MW of Firm Generation Remove 208 MW KPLP	Install 43MW 81 MWh of Standalone BESS Install 300 MW CT Install 99 MW ICE Remove 165 MW of Firm Generation Remove 208 MW KPLP	Install 43MW 81 MWh of Standalone BESS Install 300 MW CT Install 180 MW Biomass Remove 165 MW of Firm Generation Remove 208 MW KPLP
2030	Install 270MW 270 MWh of Group 1 Paired PV Install 88MW 162 MWh of Standalone BESS **Install 120 MW 480 MWh of Mahi Solar** **Install 60 MW 240 MWh of Kupehau**	Install 270MW 270 MWh of Group 1 Paired PV Install 88MW 162 MWh of Standalone BESS **Install 120 MW 480 MWh of Mahi Solar** **Install 60 MW 240 MWh of Kupehau**	Install 270MW 270 MWh of Group 1 Paired PV Install 88MW 162 MWh of Standalone BESS **Install 120 MW 480 MWh of Mahi Solar** **Install 60 MW 240 MWh of Kupehau**
2031	Remove 30 MW Kahuku Wind	Remove 30 MW Kahuku Wind	Remove 30 MW Kahuku Wind
2032	Install 4MW 7 MWh of Standalone BESS Remove 1 MW Kapolei Sustainable Energy Park	Install 4MW 7 MWh of Standalone BESS Remove 1 MW Kapolei Sustainable Energy Park	Install 4MW 7 MWh of Standalone BESS Remove 1 MW Kapolei Sustainable Energy Park
2033	Install 0MW 1 MWh of Standalone BESS Install 208 MW CC Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 0MW 1 MWh of Standalone BESS Install 208 MW CC Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 0MW 1 MWh of Standalone BESS Install 208 MW CC Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II

Year	LC_508_Staggered	LC_607_Staggered	LC_688_Staggered
2034	Install 18MW 33 MWh of Standalone BESS Remove 5 MW Kalaeloa Renewable Energy Park	Install 18MW 33 MWh of Standalone BESS Remove 5 MW Kalaeloa Renewable Energy Park	Install 18MW 33 MWh of Standalone BESS Remove 5 MW Kalaeloa Renewable Energy Park
2035	Install 400MW of Offshore Wind Install 86MW 162 MWh of Standalone BESS	Install 400MW of Offshore Wind Install 86MW 162 MWh of Standalone BESS	Install 400MW of Offshore Wind Install 86MW 162 MWh of Standalone BESS
2036			
2037	Remove 171 MW of Firm Generation	Remove 171 MW of Firm Generation	Remove 171 MW of Firm Generation
2038	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind
2039	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar
2040	Install 68MW of Aggregated DER 136 MWh Install 23MW 45 MWh of Standalone BESS	Install 68MW of Aggregated DER 136 MWh Install 23MW 45 MWh of Standalone BESS	Install 68MW of Aggregated DER 136 MWh Install 23MW 45 MWh of Standalone BESS
2041	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects
2042			
2043			
2044	Remove 20 MW of West Loch	Remove 20 MW of West Loch	Remove 20 MW of West Loch
2045	Install 0MW 933 MWh of Group 1 Paired PV Install 1706MW of Aggregated DER 3412 MWh Install 388MW 2695 MWh of Standalone BESS	Install 0MW 933 MWh of Group 1 Paired PV Install 1706MW of Aggregated DER 3412 MWh Install 388MW 2695 MWh of Standalone BESS	Install 0MW 933 MWh of Group 1 Paired PV Install 1706MW of Aggregated DER 3412 MWh Install 388MW 2695 MWh of Standalone BESS
2046	Remove 269 MW of Firm Generation	Remove 269 MW of Firm Generation	Remove 269 MW of Firm Generation
2047			
2048			
2049			
2050	Install 0MW 76 MWh of Group 1 Paired PV Install 961MW of Aggregated DER 1923 MWh Install 78MW 761 MWh of Standalone BESS	Install 0MW 76 MWh of Group 1 Paired PV Install 961MW of Aggregated DER 1923 MWh Install 78MW 761 MWh of Standalone BESS	Install 0MW 76 MWh of Group 1 Paired PV Install 961MW of Aggregated DER 1923 MWh Install 78MW 761 MWh of Standalone BESS

DRAFT

REQUEST FOR PROPOSALS

FOR

RENEWABLE DISPATCHABLE GENERATION

AND

ENERGY STORAGE

ISLAND OF O‘AHU

DECEMBER 22, 2022

Docket No. 2017-0352

Appendix J – Draft Power Purchase Agreement for Renewable Dispatchable Generation (PV + BESS) All Islands

Please see Exhibit 6, 8, and 10 of this December 22, 2022 Transmittal

Hawaiian Electric

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REQUEST FOR PROPOSALS

FOR

RENEWABLE DISPATCHABLE GENERATION

AND

ENERGY STORAGE

ISLAND OF O'AHU

DECEMBER 22, 2022

Docket No. 2017-0352

Appendix K – Draft Power Purchase Agreement for Renewable Dispatchable Generation (WIND + BESS) All Islands

Please see Exhibit 7, and 8 of this December 22, 2022 Transmittal

Hawaiian Electric

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REQUEST FOR PROPOSALS

FOR

RENEWABLE DISPATCHABLE GENERATION

AND

ENERGY STORAGE

ISLAND OF O‘AHU

DECEMBER 22, 2022

Docket No. 2017-0352

Appendix L – O‘ahu Model Firm PPA

Please see Exhibit 14 of this December 22, 2022 Transmittal

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REQUEST FOR PROPOSALS

FOR

RENEWABLE DISPATCHABLE GENERATION

AND

ENERGY STORAGE

ISLAND OF O‘AHU

DECEMBER 22, 2022

Docket No. 2017-0352

Appendix M – Draft Energy Storage Purchase Agreement All Islands

Please see Exhibit 11, and 12 of this December 22, 2022 Transmittal

Hawaiian Electric