BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAIʻI

In the Matter of the Application of HAWAIʻI ELECTRIC LIGHT COMPANY, INC. For Approval to Commit Funds in Excess of $2,500,000 for the Purchase and Installation of Item HZ.005027 Keāhole Battery Energy Storage System Project, and to Recover Costs through the Major Project Interim Recovery Adjustment Mechanism	DOCKET NO.

APPLICATION OF HAWAIʻI ELECTRIC LIGHT COMPANY, INC.

VERIFICATION

EXHIBITS 1-10

and

CERTIFICATE OF SERVICE

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Regulatory Affairs
Hawaiian Electric Company, Inc.
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APPLICATION

TO THE HONORABLE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAIʻI:

HAWAIʻI ELECTRIC LIGHT COMPANY, INC. (hereinafter "Hawaiʻi Electric Light" or the "Company") respectfully requests Commission approval to commit funds in excess of $2,500,000 (up to $16,920,000) for its Keāhole Battery Energy Storage System ("BESS") Project ("Project" or "Keāhole Bess Project").

The Company requests a Commission Decision approving the commitment of funds for the Project by mid-January 2021 to meet the Project schedule and the Guaranteed Commercial Operations Date ("GCOD") of December 30, 2022. Hawaiʻi Electric Light needs to start engineering in January 2021 to meet the GCOD.

EXECUTIVE SUMMARY

The Hawaiian Electric Companies issued the final Stage 2 Request for Proposals for Variable Renewable Dispatchable Generation and Energy Storage for the Island of Hawaiʻi (the "Stage 2 RFP")[1] in accordance with Commission Order No. 36474[2] in Docket 2017-0352. The Stage 2 RFP solicited proposals for, among other things, up to 18 megawatts ("MW") of contingency storage, and allowed the Company to submit self-build proposals subject to the requirements of the Stage 2 RFP.

The Keāhole BESS Project was submitted in response to the Stage 2 RFP as a Company self-build proposal to provide 12 MW of contingency storage.[3] As discussed further in Section VII below, the Project will provide grid services required to reduce the likelihood of customer outages and possible failure of the Hawaiʻi island grid during loss of generation and other disturbances.

As outlined in the RFP, a robust three phase bid evaluation process, approved by the Commission and overseen by the Independent Observer, evaluated the projects submitted for consideration in response to the Stage 2 RFP. Also, as part of Docket 2017-0352, a Grid Services RFP seeking Fast Frequency Response 1 ("FFR-1") proposals was issued simultaneously with the Stage 2 RFP. Evaluations for the Stage 2 RFP and the Grid Services RFP were conducted in parallel. A combined evaluation for both the contingency storage proposals submitted for the Stage 2 RFP and the FFR-1 proposals submitted for the Grid Services RFP was conducted. An energy storage only cost ($/MW) was determined for each FFR-1 proposal and each proposed contingency storage project, including both standalone

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[1] See Docket 2017-0352, *Request for Proposals for Variable Renewable Dispatchable Generation and Energy Storage Island of Hawaiʻi*, Book 5 of 7, filed August 22, 2019.
[2] See Docket 2017-0352, Order No. 36474, filed August 15, 2019.
[3] See Docket 2017-0352, *Hawaiʻi Electric Light Company, Inc Stage 2 Self-Build Proposal No. 1*, filed November 4, 2019.

storage projects and projects paired with renewable generation. Projects were ranked by lowest energy storage only cost, and the Keāhole BESS Project was selected to the Final Award Group on this basis. Another 6 MW of FFR-1 was also selected through the Grid Services RFP to reach the full 18 MW of FFR-1 needed. This was the only bid received in the Grid Services RFP for FFR-1. Combined, the two projects represented the top ranked proposals based on the lowest Energy Storage Only price of all storage and FFR-1 proposals received. Notably only one FFR-1 proposal was received for evaluation in the Grid Services RFP. The evaluation and ultimate ranking and selection of projects was overseen by the Independent Observer selected by the Commission.

According to the principles of the Framework for Competitive Bidding, and throughout the development and execution of the Stage 2 RFP, the Commission and the Company strove to ensure that the Company's self-build proposals were developed and evaluated fairly and consistently against proposals submitted by independent power producers ("IPPs"). This Application continues that intent, seeking approvals from the Commission that are consistent with the way that IPPs are treated and compensated. Specifically, the Company proposes herein that:

- The Project is approved in an expedited manner consistent with IPP Power Purchase Agreement applications, and primarily based on its selection to the Final Award Group in the Stage 2 RFP, which was approved by the Commission and executed under the supervision of the Independent Observer,
- The Project and the Company conform to the applicable requirements of the Energy Storage Power Purchase Agreement ("ESPPA"), including performance requirements, schedule requirements and adjustments, and penalties associated with non-compliance,

- Recovery of capital and operations and maintenance ("O&M") costs are capped at the amounts proposed in the winning self-build bid,
- The accounting treatments and assumptions used to develop the revenue requirements upon which the self-build bid was selected are approved, and
- A Shared Savings Mechanism ("SSM") is implemented whereby 10% of any cost savings are passed to customers.[4]

The proposed Keāhole BESS Project consists of Hawai'i Electric Light's construction of a 12 MW/12 megawatt-hour ("MWh") BESS at Hawai'i Electric Light's Keāhole Generating Station ("Keāhole Generating Station" or "KGS") in Kailua-Kona, Hawai'i and the operation of the BESS for a 20-year period. The Company's KGS site was offered to all bidders in the Stage 2 RFP as a BESS site, and is an excellent location for a number of reasons, including: (1) no additional land costs; (2) minimal site preparation; (3) proximity to the point of interconnection at the existing KGS switching station; and (4) minimal permitting requirements in an industrial area. By using the KGS site and working closely with selected partners, the Company developed a proposal that was selected to the Final Award Group in the Stage 2 RFP as providing a necessary amount of contingency storage capability at the best value to customers.

The Keāhole BESS Project is scheduled to commence construction in June 2021 with an in-service date of December 2022, at a total estimated cost of $16.9 million. The largest component of the Project cost is the contract that will cover the engineering, procurement, and construction ("EPC contract") of the Project's BESS. The interconnection of the BESS to the KGS switching station will be in addition to the aforementioned BESS EPC contract cost. Hawai'i Electric Light staff, Hawaiian Electric personnel, and outside consultants will perform

[4] See Docket 2018-0088, *Companies' Correction to their Second Updated Comprehensive Proposal*, filed May 14, 2020

development, project management, and engineering work on the Project.

The Commission's Major Project Interim Recovery ("MPIR") Guidelines ("MPIR Guidelines")[5] specifically identify energy storage projects as Grid Modernization Projects that are eligible for recovery through the MPIR adjustment mechanism. Accordingly, Hawai'i Electric Light proposes that the costs of the Keāhole BESS Project be recovered through the MPIR adjustment mechanism until base rates that reflect the revenue requirements associated with the Project costs take effect in a future Hawai'i Electric Light rate case.

Hawai'i Electric Light respectfully submits that the proposed Project is reasonable and in the public interest, and should be approved, as:

- The Project was selected through a Commission-approved competitive procurement process that has resulted in the lowest cost to customers for a required resource;
- The Project incorporates the cost, performance, and financial obligations required of a self-build project as required by the Stage 2 RFP, consistent with applicable ESPPA requirements, as set forth in the Self Build Option Team Certification (See Exhibit 1); [6]
- The parameters of the Project are consistent with the Power Supply Improvement Plan ("PSIP") Update Report and the Commission's Inclinations;[7]

[5] The Commission's *MPIR Guidelines* ("MPIR Guidelines") are set forth in Attachment A to Order No. 34514 *Establishing Performance Incentive Measures and Addressing Outstanding Schedule B Issues* ("Order 34514"), filed April 27, 2017 in Docket No. 2013-0141. See Section III.B.1.(f) of the MPIR Guidelines.
[6] See Docket No. 2014-0183, Decision and Order ("D&O") 34696 at 3: "The commission expects the Companies to continuously improve and refine their resource planning tools and methods, and employ these tools to support appropriate competitive procurement processes and Project applications in the near term."
[7] The Commission's Inclinations on the Future of Hawaii's Electric Utilities ("Commission's Inclinations") were appended as Exhibit A to D&O No. 32052, filed April 28, 2014 in Docket No. 2012-0036.[8] Docket No. 2014-0183, *PSIPs Update Report: December 2016* at I-3, filed December 23, 2016.

- The Project contributes to the State's goal of greater energy security and energy self-sufficiency.

I.

REQUESTED APPROVALS

Hawai'i Electric Light respectfully requests that the Commission issue a D&O:

1. Approving implementation of the Keāhole BESS Project at a total current estimated cost of $16.9 million as further described in Exhibit 2;
2. Approving a commitment of funds in excess of $2,500,000 for the Project, net of customer contributions, as further described in Section VII.A.3 below, pursuant to Paragraph 2.3(g)(2) of the Commission's General Order No. 7, as modified by D&O No. 21002, filed May 27, 2004 in Docket No. 03-0257 ("G.O. 7");
3. Approving the proposed accounting and ratemaking treatment for the Project, as further described in Section VIII below, including:
    a. As further described in Exhibit 3, recovery of the Project costs through the MPIR adjustment mechanism established in Order 34514, filed April 27, 2017 in Docket No. 2013-0141, until base rates that reflect the revenue requirements associated with the Project costs take effect in a future rate case or general rate setting proceeding; and
    b. Acknowledgement of the new asset category for accounting purposes, FERC plant account 348 Energy Storage Equipment – Production and the Company's intent to include the battery related cost in this account; and
    c. Depreciation of the battery related cost over 20 years (5% annually);
    d. Rate of return as approved in the Company's most recent rate case; and
    e. An SSM under which the Company would recover 90% of any cost

savings under the approved cost cap.

4. Determining that a public hearing is not required, pursuant to Section 269-27.5 of the Hawai‘i Revised Statutes (“HRS”);

5. Approving the construction of the 69kV sub-transmission line for the Project above the surface of the ground, as discussed in Section IX below, pursuant to Section 269-27.6(a) of the “HRS”;

6. Granting Hawai‘i Electric Light such other and further relief as may be just and Equitable in the premises.

II.

HAWAI‘I ELECTRIC LIGHT COMPANY, INC.

Hawai‘i Electric Light, whose principal place of business and whose executive office is located at 1200 Kilauea Avenue, Hilo, Hawai‘i, is a corporation duly organized under laws of the Republic of Hawai‘i on or about December 5, 1894, and now exists under and by virtue of the laws of the State of Hawai‘i. Hawai‘i Electric Light is an operating public utility engaged in the production, purchase, transmission, distribution and sale of electricity on the island of Hawai‘i.

III.

CORRESPONDENCE

Correspondence and communications regarding this Application should be addressed to:

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P.O. Box 2750
Honolulu, Hawai‘i 96840-0001

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Regulatory@hawaiianelectric.com

IV.

EXHIBITS

The following exhibits are provided in support of this Application:

Exhibit 1 – Keāhole BESS Applicable Energy Storage Power Purchase Agreement Provisions

Exhibit 2 – Keāhole Project Cost Summary, Vendor Pricing and Project Risk

Exhibit 3 – Keāhole BESS MPIR Model (Illustrative Hawai'i Electric Light Decoupling Calculation Workbook)

Exhibit 4 – Keāhole Site Plan View

Exhibit 5 – Net Revenue Requirement and Bill Impact

Exhibit 6 – Contingency Energy Storage Update Study

Exhibit 7 – Project Justification with Business Case Support for the Keāhole BESS Project

Exhibit 8 – Community Outreach Plan

Exhibit 9 – Public Comments, Questions, and Responses

Exhibit 10 – Confidentiality Log

Portions of the Exhibits have been redacted as confidential and unredacted versions of the same will be filed upon the issuance of an appropriate protective order in this Docket. As set forth in Exhibit 10, the redacted information contains confidential information in the form of negotiating positions, proposals, strategies, financial and pricing information, which if publicly disclosed, could disadvantage and competitively harm the Companies in future responses to RFPs.

Hawai'i Electric Light acknowledges that certain types of information identified as confidential in the Exhibits, including the Company's costs, have been disclosed as public information in other documents or proceedings. In this instance, however, the specificity of that information, whether or not it reflects modification from information previously disclosed, and how it has been applied in developing the Company's response to the Stage 2 RFP should be considered and treated as confidential.

The public disclosure of what is included in the Company's bid would provide a recipe, enabling competitors to not provide their best price in response to subsequent RFP's, but rather a price at or slightly below what is offered by Hawai'i Electric Light. The Company contends that disclosure of the information will not only harm the Company competitively, but would also have an adverse impact on subsequent RFPs.

V.

STATUTORY PROVISION OR AUTHORITY

The approvals in this Application are requested pursuant to Sections 226-18, 269-6, 269-6(b), 269-7, 269-16, 269-27.5, 269-27.6, 269-91 and 269-92 of the HRS; Section 16-601-74 of the *Rules of Practice and Procedure Before the Public Utilities Commission*, Title 16, Chapter 601 of the Hawai'i Administrative Rules ("HAR"); G.O. 7 Paragraph 2.3(g)(2), as modified by D&O 21002 filed May 27, 2004 in Docket No. 03-0257, Order No. 36474 *Approving the Hawaiian Electric Companies' Phase 2 Draft Requests for Proposals, with Modifications*, issued August 15, 2019 in Docket No. 2017-0352; Decision and Order No. 34696, filed July 14, 2017 in Docket No. 2014-0183 (PSIP docket); the Commission's *MPIR Guidelines* ("MPIR Guidelines") as set forth in Attachment A to Order No. 34514 *Establishing Performance Incentive Measures and Addressing Outstanding Schedule B Issues* ("Order 34514"), filed April 27, 2017 in Docket No. 2013-0141; and D&O No. 35606 in Docket No. 2016-0431 issued on July 30, 2018 in the Hawaiian Electric Companies' most recent depreciation rates proceeding.

VI.

ROLE OF ENERGY STORAGE

In the PSIP Update Report, the Hawaiian Electric Companies discussed how energy storage technologies are increasing the flexibility to utilize renewable technologies in electric grids and revolutionizing the way customers manage their energy costs.[8] The Companies' grid modernization stakeholder outreach efforts have revealed that:

> Storage (particularly battery storage, at present) is seen by all stakeholder groups as the 'Holy Grail' of Hawai'i's energy future, to quote one of the energy experts. It must be noted, however, that some residential customers believe that energy can be stored in the grid currently and used when needed. Customers across all stakeholder groups want to see larger-scale, grid-connected storage located around each of the islands to help stabilize the grid and increase efficiency . . . .[9]

The Commission's Inclinations[10] specifically identify the need to aggressively seek lower-cost, new utility-scale renewable resources as a step toward creating a 21st century generation system, and further state that Hawaiian Electric should modernize the generation system to achieve a future with high penetrations of renewable resources, in which the Company should utilize new tools such as energy storage in order to promote grid flexibility efficiently and cost-effectively. In Act 97 of the 2015 Hawai'i Session Laws, the Legislature increased the Renewable Portfolio Standard ("RPS") goals for the State's electric utilities, including an unprecedented 100% RPS goal by 2045. As the Companies increase the amount of variable energy production installed and contracted for, energy storage will play a growing role in distributing that energy throughout the day to coincide with demand and providing grid services such as FFR-1 or contingency reserves to maintain the reliability of the grid.

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[8] Docket No. 2014-0183, *PSIPs Update Report: December 2016* at I-3, filed December 23, 2016.
[9] Docket No. 2017-0226, *Modernizing Hawai'i's Grid For Our Customers*, filed August 29, 2017 at 9.
[10] Docket No. 2012-0036, D&O No. 32052, Exhibit A, filed April 28, 2014.

In support of these policies, the Company solicited FFR-1 resources for the island of Hawaiʻi, which could be fulfilled by standalone contingency reserve energy storage Projects. The proposed Keāhole BESS Project, which is a 12 MW/12 MWh battery system targeted for service in 2022, will be a dual-purpose energy storage Project to provide regulation/ramping functions, as well as providing FFR-1 for Contingency Reserves.

VII.

PROJECT INFORMATION

A. PROJECT DESCRIPTION

1. Project Scope

The Keāhole BESS project proposes to install, own, and operate a 12 MW/12 MWh BESS at the Keāhole Generating Station for a 20 year term. The energy storage system would be grid-tied via the Keāhole switching station. The proposed energy storage system is intended to satisfy the requirements for a "standalone contingency reserve energy storage" project, as defined in the Stage 2 RFP and the requirements noted in the associated ESPPA.

The BESS will consist of 12 pad-mounted Tesla Megapacks, 6 pad-mounted medium voltage transformers, a Tesla site controller system, medium voltage switchgear, and a single step-up transformer ("GSU"). The Company selected Tesla's Megapack lithium ion battery system for the Project based on market pricing and the ability of this technology to meet all technical requirements of the Project.

Each Megapack is a modular outdoor rated cabinet, housing battery racks, inverters, and an integrated cooling system. Several Megapacks are then tied to each of the medium voltage transformers that step the voltage up from 480 V to 13.8 kV. The 12 Megapack configuration will provide the rated 12 MW/12 MWh power and energy capacities, and the rated number of battery cycles for the 20-year Project life.

The combined output from the medium voltage transformers will run through medium voltage switchgear before the voltage is stepped up again by the GSU to 69 kV. The output from the GSU will tie into the 69 kV system via the overhead bus running to an extension of an existing 69 kV bay to be constructed at the Keāhole Switching Station. This line connection between the GSU and 69kV bus is approximately 15 feet long, running from a 10'-6" height to 19'-0" height at the bus.

The BESS also includes a system controller and battery management system ("BMS"), which controls the entire battery system and integrates the charging and discharging of the BESS with Hawaiʻi Electric Light's energy management system ("EMS"). The site controller and BMS will be integrated into the Company's telecommunications network and receive the dispatch commands from the EMS. The BMS will control individual inverters and the charging/discharging of the battery racks to provide the required services while optimizing BESS performance and providing monitoring, protection, and balancing of the battery modules.

2. Use Case and Battery Performance.

The facility will provide frequency regulation, fast frequency response, and contingency reserve capabilities as required by the Stage 2 RFP. Although the proposed system is optimized for the primary function of FFR-1 and contingency reserve functions specified in the RFP, the proposed system also has the installed capability to serve as an energy-shifting resource, and will be black-start and grid-forming capable, as the RFP required.

The proposed Project has a lifecycle of 20 years, throughout which the Company will maintain the performance and capacity of the BESS to the parameters required in the Stage 2 RFP. This will be accomplished by three complementary efforts: initial design capacity, a comprehensive system maintenance plan, and a manufacturer warranty.

The Project will be designed with the up-front installed capacity to maintain the required performance of the system for 20 years, taking into account expected system degradation over that period and the expected usage. No battery system augmentation is expected to be required over the life of the Project. In the event that degradation exceeds the forecast amount, the system warranty will provide for battery replacement or augmentation as required. The Company and Tesla have developed a maintenance plan which will keep the system operating at the required parameters.

3. Project Location

The Project will be built at Hawaiʻi Electric Light's Keāhole Generating Station as shown in Exhibit 4, in an area adjacent to the Keāhole Switching Station. Approximately 0.9 acres are reserved for the Project. The existing KGS firefighting systems will be extended to incorporate the new BESS system.

4. Project Staffing

No additional staffing is planned to operate and maintain the Keahole BESS. Company personnel will perform routine maintenance on the BESS and the supporting equipment such as transformers. A maintenance contract with Tesla for the duration of the Project will ensure that the system is maintained and can meet the performance requirements specified in the Stage 2 RFP for the life of the Project.

5. Applicable ESPPA Provisions

The model ESPPA was drafted and intended to govern the relationship between Company, as utility operator and purchaser of Energy Storage Services, and a third-party "Seller," as owner and operator of a battery energy storage system and seller of the availability of the Energy Storage Services. Because the self-build option ("SBO") does not fit within this contract paradigm, and the ESPPA was not specifically drafted to address a SBO, Section 1.9 of the Stage 2 RFP,[11] which sets forth the procedures for self-build proposals, recognized that the SBO would not be required to enter into the model ESPPA; rather, the SBO would be asked to commit to comply with specific ESPPA provisions set forth in Appendix G Attachment 1, Self-Build Option Team Certification Form:

> * * * *
>
> . . . Except where specifically noted, an SBO Proposal must adhere to the same price and non-price Proposal requirements as required of all Proposers, as well as certain PPA requirements, such as milestones and liquidated damages, as described in Appendix G. The non-negotiability of the Performance Standards shall apply to any SBO to the same extent it would for any other Proposal. Notwithstanding the fact that it will not be required to enter into an RDG PPA or ESPPA with the Company, a Self-Build Proposer will be required to note its exceptions, if any, to the RDG PPA and/or ESPPA in the same manner required of other Proposers, and will be held to such modified parameters if selected. In addition to its Proposal, the Self-Build Team will be required to submit Appendix G Attachment 1, Self-Build Option Team Certification Form, acknowledging . . . adherence to PPA terms and milestones required of all proposers and the SBO's proposed cost protection measures.
>
> The cost recovery methods between a regulated utility SBO 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. (Emphasis in original).
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> * * * *

Section 3.8.4 of the Stage 2 RFP similarly notes that the SBO will not execute the model ESPPA but would be held to the provisions stated in the Self Build Option Certification, subject to any proposed SBO modifications, and as adjusted with the approval of the Commission:

> If selected, a Self-Build Proposer will not be required to enter into a PPA or ESPPA with the Company. However, the Self-Build

[11] See Docket 2017-0352, *Request for Proposals for Variable Renewable Dispatchable Generation and Energy Storage Island of Hawai'i*, Book 5 of 7, filed August 22, 2019.

> Proposer will be held to the proposed modifications to the RDG PPA and/or ESPPA, if any, it submits as part of the SBO in accordance with Section 3.8.7. Moreover, the SBO will be held to the same performance metrics and milestones set forth in the RDG PPA and/or ESPPA to the same extent as all Proposers, as attested to in the SBO's Appendix G, Attachment 1, Self Build Option Certification submittal. If liquidated damages are assessed, they will be paid from shareholder funds and returned to customers through the Purchased Power Adjustment Clause ("PPAC") or other appropriate rate adjustment mechanisms.
>
> To retain the benefits of operational flexibility for a Company-owned facility, the SBO 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 PPA with PUC approval. (Emphasis in original).

Further recognizing that the SBO does not fit squarely within the model ESPPA contract paradigm, the Self-Build Option Team Certification specifically acknowledged that ESPPA terms related to commercial and legal interactions between "Seller" and the Company were not applicable:

> The SBO Proposal will be consistent with the scope of work and responsibilities of the "Seller" under the terms of the applicable Model PPA excluding inapplicable terms related to commercial and legal interactions between the Seller and the Company.[12]

The Self Build Option Team Certification further served to identify the particular ESPPA provisions that would apply to the Proposal. Specifically, pursuant to the Self Build Option Team Certification, the Self Build Team agreed that the SBO Facility will be designed and constructed to:

> a. Achieve the Performance Standards identified in Section 3 - Performance Standards, in Attachment B of the applicable Model [ESPPA] 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);[13]

[12] Self Build Option Team Certification, Section D.1. (emphasis added).
[13] Self Build Option Team Certification, Section D.2.a.

b. Meet the performance metrics as specified in . . . Article 4 of the ESPPA . . . [f]or 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;[14]
c. Pass the Acceptance Test specified in Attachment N - Acceptance Test General Criteria of the applicable Model . . . ESPPA;[15]
d. Pass the Control System Performance Test specified in Attachment O – Control System Acceptance Test Criteria of the applicable Model . . . ESPPA;[16]
e. If applicable, pass the On-line Performance Test specified in . . . Attachment T - Facility Tests of the Model ESPPA;[17] and
f. Meet the project milestones identified in the SBO Proposal no later than the dates specified therein, which shall be consistent with the guaranteed project milestones required in Attachment K - Guaranteed Project Milestones of the Model . . . ESPPA (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.[18]

In addition, under the Self Build Option Team Certification, the Self Build Team further agreed that the Company:

a. [Will] achieve the reporting milestones identified in the SBO Proposal no later than the dates specified therein, which shall be consistent with the reporting milestones required in Attachment L - Reporting Milestones of the Model . . . ESPPA (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;[19]
b. Will be subject to the applicable liquidated damages for the . . . ESPPA 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. Notice of any liquidated damages assessed and amounts of such liquidated damages will be provided to PUC and Consumer Advocate;[20] and

[14] *Id.* at Section D.2.b.b.3.
[15] *Id.* at Section D.2.c.
[16] *Id.* at Section D.2.d.s
[17] *Id.* at Section D.2.e.
[18] *Id.* at Section D.2.g.
[19] *Id.*, Section D.2.h.
[20] *Id.*, Section D.2.i.

c. Will provide annual report to PUC and Consumer Advocate on performance metrics.[21]

Finally, the Self Build Option Team Certification contemplated that the applicable ESPPA terms would be reaffirmed in the GO7 application for any selected SBO project and the associated approval order, as is being done in this Application.[22]

Thus, consistent with the above, the Self Build Team in its Proposal agreed to: (1) meet or achieve specific ESPPA performance standards, metrics, tests, and project milestones, (2) be subject to applicable liquidated damages, (3) provide notice of any liquidated damages assessed and amounts of such liquidated damages to the Commission and Consumer Advocate, (4) provide notice of completion of project and reporting milestones and any delay to the Commission and Consumer Advocate, and (5) provide an annual report to the Commission and Consumer Advocate on performance metrics.[23]

In addition, and as required by the Stage 2 RFP, the Self Build Team noted certain inapplicable ESPPA terms and exceptions in Attachment 2.4.1 to its Proposal. In particular, Attachment 2.4.1. identified ESPPA provisions that were inapplicable because the SBO and the Company were the "same legal entity" and because the provisions were not applicable to the SBO (e.g., because the provisions applied to solar projects).[24] The Company acknowledges that the list of inapplicable terms and exceptions set forth in Attachment 2.4.1. is not exhaustive as it does not include a number of provisions that are not applicable to the Project, as reflected in Exhibit 1; however, the Company does not believe that this oversight should have a material

[21] *Id.*, Section D.2.k.
[22] *Id.*, Section D.2.j.
[23] *See* Self Build Option Team Certification.
[24] Attachment 2.4.1 also referenced provisions the SBO expected would be incorporated into the GO7 application process.

impact on this Application, especially where the Stage 2 RFP makes clear that the SBO will not be required to enter into the ESPPA and where the Self Build Option Team Certification acknowledged and agreed that terms of the ESPPA related to commercial and legal interactions between the Seller and the Company are inapplicable and excluded.[25]

Therefore, Exhibit 1, attached hereto, reflects for convenience, a consolidation of applicable provisions of the ESPPA related to performance standards, metrics, tests, project milestones, and liquidated damages that the Company has agreed will govern the Project, as set forth in and subject to the Self Build Option Team Certification. As discussed above, because the SBO does not fit the model ESPPA contract paradigm, the ESPPA language itself in turn does not always align with an SBO project. As such, in addition to excluding inapplicable terms, in some areas the Company has edited ESPPA provisions for application to a SBO while attempting to retain the original intent of the provision; in other areas, for clarity, the Company will note how the Company intends the provisions would be implemented for a SBO – for example, for all sections in Exhibit 1 providing for an interaction between "Seller" and "Company," such interaction shall be incorporated into the Company's internal project management, operations, and/or oversight processes. In addition, similar to an IPP, the Company may adjust interim milestone dates based on the results of the Interconnection Requirements Study which is ongoing.

B. PROJECT COSTS

1. Capital Cost

The total capital cost for the Keāhole BESS Project which was bid into the Stage 2 RFP is $16.9 million. As required by the Stage 2 RFP and to be consistent with how an IPP would be compensated, the Company proposes to cap the recovery of the Project's capital cost at the $16.9

[25] Self Build Option Team Certification, Section D.1.

million bid amount. The Company also proposes an SSM whereby 90% of any capital cost savings, as measured by the difference between the proposed $16.9 million and the actual project capital cost, be included in the Company's allowed cost recovery, as described in the accounting treatment below. This capital cost SSM is more beneficial to customers than an IPP would allow under the ESPPA.

The largest component of the cost estimate is for the EPC contract, which will include:

a. Engineering of the BESS (including hardware, and software programming of the battery management and control systems);

b. Procurement of BESS equipment including Megapacks, wiring, medium voltage transformers, medium voltage switchgear, and control systems;

c. Site development and construction;

d. System commissioning and integration; and

e. Permitting.

See Exhibit 2 of this Application for cost details.

The remaining Project scope of work outside of the EPC contractor's responsibility may be conducted by Hawaiʻi Electric Light personnel or be contracted out, and includes the following:

a. Engineering, procurement, and installation of the high voltage interconnection and metering equipment, including the step up transformer, the new 69 kV bay and breakers at the Keāhole Switching Station, and the overhead connection to the new bus extension;

b. Labor and materials to integrate the BESS with Hawaiʻi Electric Light's EMS; and

c. Project management of the Hawaiʻi Electric Light work and management of the EPC contract.

2. O&M Costs.

In addition to Project capital costs, O&M costs were also provided in the Company's self-build proposal into the Stage 2 RFP. These forecast O&M costs include Company labor for the proposed Project, as well as the Tesla maintenance support contract, and other costs associated with the 20 year operation of the Project. Details of the forecast O&M costs are provided in Exhibit 5.

As indicated in the Stage 2 RFP, the Company proposes to cap the recovery of O&M costs at the amounts provided in the Company's self-build proposal. The Company also proposes an SSM whereby 90% of any O&M cost savings, as measured by the difference between the proposed annual amounts shown in Exhibit 5 and the actual project annual O&M costs, be included in the Company's allowed cost recovery, as described in the accounting treatment below. This SSM is more beneficial to customers than an IPP would allow under the ESPPA.

C. PROJECT JUSTIFICATION

Hawai'i Electric Light respectfully submits that the proposed Project is reasonable and in the public interest, and should be approved for the following reasons:

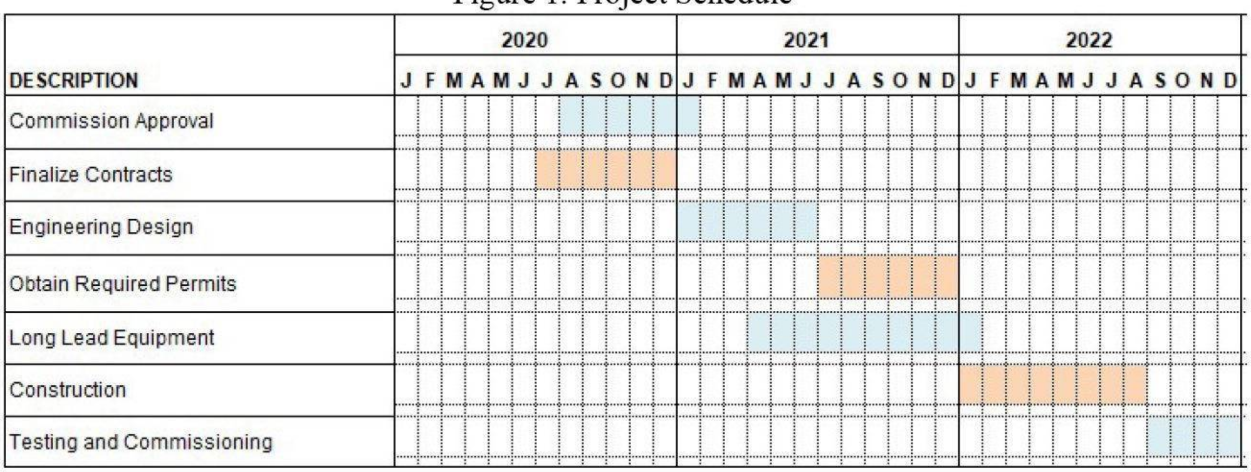
1. The Project was selected to the Final Award Group in the Stage 2 RFP, the requirements and procedures for which were approved by the Commission, and overseen by the Independent Observer.
2. The Stage 2 RFP, as approved, was consistent with the PSIP Update Report and the Commission's Inclinations, and contributed to the State's goal of greater energy security and energy self-sufficiency.

3. The Project will provide FFR-1[26] service that is required in sufficient quantity and with characteristics necessary to help avoid customer outages and possible failure of the system during loss of generation, and other disturbances. An analysis of the FFR-1 requirements for the Hawai‘i Island grid, which includes the planned Stage 1 and Stage 2 RFP projects, is provided in Exhibit 6.

D. PROJECT SCHEDULE

The Keāhole BESS Project is proposed to be placed in service in December 2022, as required by the Stage 2 RFP. Installation and construction of the Project is anticipated to commence in June 2021. A high-level Project schedule showing major tasks is provided in Figure 1 below:

Figure 1: Project Schedule



The “critical path” schedule for the Project (i.e., the sequence of events that cannot be delayed without delaying completion of the entire Project) includes the following items:

1. The receipt of a final D&O approving this Application by the Commission within 6 months from the Application filing date;

[26] The Project will provide FFR-1 service which can be deployed within 12 cycles (200 milliseconds). FFR-2 can react within 30 cycles (500 milliseconds).

2. Engineering, procurement, and delivery of the BESS is estimated to take 18 months from the Notice to Proceed;[27]

3. Installation of the BESS and final tie-in to the 69 kV system is estimated to take approximately 8 months; and

4. Testing and commissioning of the BESS is estimated to take approximately 4 months.

To the extent that the time to complete any of the critical path items above can be reduced, the proposed BESS can be placed in service earlier than scheduled and used on the system. Correspondingly, additional time needed to complete any of the above steps will result in a later in-service date.

Other required Project approvals and tasks, while necessary to complete the Project, have some flexibility as to when they need to be completed while still meeting the anticipated Project in-service date. However, they could become critical path items if significantly delayed or if their schedules are affected by compression of other critical path items.

VIII.

ACCOUNTING AND RATEMAKING TREATMENT

A. MPIR RECOVERY

Hawaiʻi Electric Light is requesting to recover the costs of the Project through the MPIR adjustment mechanism until base rates that reflect the revenue requirements associated with those costs take effect in the next rate case or general rate setting proceeding.

The purpose of the MPIR adjustment mechanism is to provide a mechanism for recovery of revenues for net costs of approved Eligible Projects placed in service between general rate

[27] "Notice to Proceed" is a notification from the Company to a contractor stating the date the contractor can begin the work subject to the conditions of the contract.

cases, that is not provided for by other effective tariffs. Pursuant to Section III.B.1 of the MPIR Guidelines:

> Projects and costs that may be eligible for recovery through the MPIR adjustment mechanism are Major Projects subject to review and approval in accordance with the applicable provisions of General Order No 7, including but not restricted to the following illustrative examples, subject to the Commission's approval in accordance with these Guidelines:
>
> (a) Infrastructure that is necessary to connect renewable energy Projects. Infrastructure Projects such as transmission lines, interconnection equipment and substations, which are necessary to bring renewable energy to the system. For example, renewable energy Projects, such as wind farms, solar farms, biomass plants and hydroelectric plants, not located in proximity to the electric grid must overcome the additional economic barrier of constructing transmission lines, a switching station and other interconnection equipment. Building infrastructure to these Projects will encourage additional renewable generation on the grid;
>
> (b) Projects that make it possible to accept more renewable energy. Projects that can assist in the integration of more renewable energy onto the electrical grid. For example, new firm generation or modifications to firm generation to accept more variable renewable generation or energy storage and pumped hydroelectric storage facilities that allow a utility to accept and accommodate more as-available renewable energy;
>
> (c) Projects that encourage clean energy choices and/or customer control to shift or conserve their energy use. Projects that can encourage renewable choices, facilitate conservation and efficient energy use, and/or otherwise allow customers to control their own energy use. For example, smart meters would allow customers to monitor their own consumption and use of electricity and allow for future time-based pricing programs. Systems such as automated appliance switching would provide an incentive to customers to allow a utility to mitigate sudden declines in power production inherent in as-available energy;
>
> (d) Approved or Accepted Plans, Initiatives, and Programs. Capital investment Projects and programs, including those transformational Projects identified within the Companies' ongoing planning and investigative dockets, as such plans

may be approved, modified, or accepted by the Commission, and Projects consistent with objectives established in investigative dockets;

(e) Utility Scale Generation. Electric utilities may seek recovery of the costs through the MPIR adjustment mechanism for utility scale generation that is renewable generation or a generation Project that can assist in the integration of more renewable energy onto the electrical grid;

(f) Grid Modernization Projects. Projects such as smart meters, inverters, energy storage, and distribution automation to enable demand response.

Section III.B.1.(f) of the MPIR Guidelines specifically identifies energy storage Projects under the umbrella of Grid Modernization Projects that are eligible for recovery through the MPIR adjustment mechanism. In addition, Section III.B.1(b) of the MPIR Guidelines, Projects that make it possible to accept more renewable energy, expressly recognizes energy storage as allowing a utility to accept and accommodate more as-available renewable energy and therefore eligible for recovery through the MPIR adjustment mechanism. Moreover, the Project also qualifies under Section III.B.1.(d) of the MPIR Guidelines as the proposed BESS will support the Company's PSIPs. Accordingly, the Company maintains that the proposed Project is eligible for recovery through the MPIR adjustment mechanism.

Pursuant to Section III.C.2.b of the MPIR Guidelines:

Costs eligible for the MPIR adjustment mechanism include:

(i) Return on the net of tax average annual undepreciated investment in allowed Eligible Projects during MPIR for each Project at rate of return to be determined in the review of each Eligible Project application, as approved by the commission;

(ii) Recorded depreciation accruals (at a rate and methodology to be determined in review of each Project's application, and as approved by the Commission) to begin on the following January 1st after the month of the in-service date of the Project;

(iii) Other relevant costs, applicable taxes, and/or offsetting cost savings, approved by the Commission.

Please refer to Exhibit 2 for a breakdown of the Project costs by these categories.

Section III.C.3.c of the MPIR Guidelines provides that: "A business case study shall be submitted with each application identifying and quantifying all operational and financial impacts of the Eligible Project and illustrating the cost/benefit tradeoffs that justify proceeding with the Project to the extent that such impacts can reasonably be determined." Section III.C.3.e of MPIR Guidelines similarly provides that:

> A detailed business case study shall be included, covering all aspects of the planned investments and activities, indicating all expected costs, benefits, scheduling and all reasonably anticipated operational impacts. The business case shall reasonably document and quantify the cost/benefit characteristics of the investments and activities, indicating each criterion used to evaluate and justify the Project, including consideration of expected risks and ratepayer impacts. The business case should also clearly outline how it will advance transformational efforts with appropriate quantifications, to the extent such quantifications can reasonably be determined.

The Company maintains that the business case provided as Exhibit 7 meets the criterion for business cases set forth in the MPIR Guidelines.

Section III.C.3.g of the MPIR Guidelines requires that specific criteria are proposed for the determination of used and useful status, in order to place the proposed Project into service. In the case of the Keahole BESS project, the Company has committed to comply with the technical and performance standards detailed in the ESPPA. Included in the ESPPA provisions to which the Company has committed above are completion of the acceptance tests required of any IPP. To be consistent with the requirements placed on an IPP in order to achieve commercial operation, the Project will complete the same tests in order to be placed into service.

Accordingly, the Company is requesting initial recovery of the costs of this Project through the MPIR adjustment mechanism.

As noted above, the Keāhole BESS Project is proposed to be placed in service in December 2022. The Company is seeking recovery of the Project costs through the MPIR adjustment mechanism until base rates that reflect the revenue requirements associated with those costs take effect in a future rate case or the next general rate setting proceeding.

Based on an in-service date of December 2022, which is the date provided in the self-build proposal as the Guaranteed Commercial Operation Date ("GCOD") to be consistent with an IPP proposal, Exhibit 3[28] provides an illustrative example of the schedules that would be filed as part of the MPIR process, which will trigger an adjustment to target revenues by an estimated annualized amount of $2,201,000[29] starting January 1, 2023.

B. ACCOUNTING TREATMENT

The Company is requesting special accounting treatment for the battery related cost of this Project to depreciate such cost over 20 years (5% annually) as used in the RFP and revenue requirements for the annual depreciation expense. This depreciation duration is based on the 20 year time span of the project, as detailed in the Company's self-build proposal, which is in turn based on the battery manufacturer's assessment of the optimum battery system lifespan. The 20 year depreciation schedule was used as the basis for the revenue requirements provided in the Company's self-build proposal. Since these revenue requirements served as the basis upon which the self-build proposal was selected to the Final Award Group, the Company maintains

[28] Exhibit 3 is included to illustrate how this project will flow through the MPIR mechanism and the approximate impact on annual target revenues. This should be considered illustrative only and is subject to change. This illustration is based on the project budget and estimated date of completion as described above. The target revenue illustration as shown in Exhibit 3 includes amounts filed in Transmittal 20-03 Consolidated (Decoupling) filing which was filed on June 5, 2020. Upon completion and being placed in service, the Company will prepare and file the MPIR filing in accordance with the approved guidelines. The MPIR filing will be based on actual recorded costs and the detailed classification of the costs in the depreciation and tax calculations. Further, the target revenues will be subject to the amounts approved in the applicable decoupling filing as of the filing date.
[29] See Exhibit 3, Schedule B1. Calculated as the difference between line 37 and line 36 ($159,285,000 - $157,084,000 = $2,201,000) and Schedule L, line 2.

that this accounting treatment is, by extension, part of the winning bid and should be treated as such in order to be considered equivalent to an IPP.

The 20 year depreciation schedule would apply to the battery system, which for an IPP would be considered the "Facility" as defined in the Stage 2 RFP. For those interconnection assets of the Project which for an IPP project would be defined as "Company Owned" in the Stage 2 RFP, current approved depreciation rates would apply. Since the self-build proposal assumed a 20 year depreciation schedule for the entire capital cost of the project, the application of current approved depreciation rates for the interconnection portion of the project results in lower revenue requirements than those provided in the self-build proposal over the 20 year life of the Project. A side-by-side comparison of the annual revenue requirements provided in Exhibit 5 (using approved depreciation for the interconnection portion of the project and a 20 year schedule for the BESS) to the revenue requirements provided in the self-build proposal (using 20 year depreciation for the full capital cost of the project) shows that the proposed treatment will result in additional cost savings to customers over the life of the project, compared to the pricing basis upon which the Company's self-build proposal was selected.

Also, the Company hereby notifies the Commission of the establishment of a new asset category for accounting purposes: Federal Energy Regulatory Commission ("FERC') plant account 348 Energy Storage Equipment – Production[30] for this battery related cost. The new asset category is consistent with FERC Uniform System of Accounts and the notification is in accordance with the Commission's D&O No. 35606 in Docket No. 2016-0431 issued on July 30, 2018 in the Hawaiian Electric Companies' most recent depreciation rates proceeding. [31] As

[30] The FERC *Uniform System of Accounts*, states that "This account shall include the cost installed of energy storage equipment used to store energy for load managing purposes."

[31] The D&O states that, "For new asset categories that arise in the future for which no depreciation rates are currently approved, the Companies shall utilize the functional composite depreciation rates of comparable asset

mentioned above, the Company is requesting special accounting treatment for the battery system costs of the Project instead of utilizing the functional composite depreciation rate of a comparable asset category as approved in Order No. 35606. The depreciation rate for plant account 348 used to derive the annual depreciation expense in Exhibit 3 is the 5% annual rate as requested in this application. The current approved depreciation rates will be used for the other components of the Project.

C. REVENUE REQUIREMENTS:

An overview of the various revenue requirement components impacted by the Keāhole BESS Project is provided in Exhibit 5 of this Application. These high-level revenue requirement calculations include simplifying assumptions (e.g., Project placed in service December 2022; capital components are not parsed into specific classifications, rather are treated as one unit to which the most likely treatment applies; 20-year expected useful life). When the Company files certification of the Project completion/in-service date, detailed calculations will be provided based on actual information and the rates in place at that time, as discussed further below. An illustrative MPIR calculation for the Keāhole BESS Project is provided in Exhibit 3 and also discussed further below.

The following is a summary of the proposed ratemaking treatment of the various costs impacted by this Project, which are described in further detail in Table 14 below:

Table 1: Proposed Ratemaking Treatment of Various Impacted Costs

Cost Component or Savings	Proposed Ratemaking Treatment
Keāhole BESS Capital	MPIR
Avoided Fuel	Energy Cost Recovery Clause ("ECRC")
Avoided Purchased Power	ECRC/Power Purchase Adjustment Clause ("PPAC")

categories approved by the commission in this proceeding. The Companies shall notify the Consumer Advocate and the commission of the new asset category, identify the composite depreciation rate to be applied, and explain the basis for selecting the rate." See Ordering Paragraph 2 in D&O No. 35606, Docket No. 2016-0431 at page 39.

Keāhole BESS O&M	MPIR
Emissions Fees	Normal Operations
Avoided Fuel Inventory	Normal Operations

The Company is requesting cost recovery of the capital and O&M components through the MPIR adjustment mechanism. The various revenue requirement components and the vehicles to address cost recovery are addressed below.

1. Capital Revenue Requirements

Capital Revenue Requirements ($16.9 million) are based on the following assumptions (see page 2 of Exhibit 5):

a. Depreciation assumptions (MPIR Guidelines Section III.C.2.ii) – The net revenue requirements assume a 20-year expected useful life of the Project. This is a high-level, simplified approach for the economic analysis. The MPIR revenue requirement will be based on the depreciation rates in place at the time of the filing for the Transmission and Substation costs and a 20-year (5% annual) depreciation rate for the battery related costs of the project as requested in this application.

b. Service life assumption – The revenue requirements assume a service life of 20 years.

c. Rate of return assumption (MPIR Guidelines Section III.C.2.i) – The return on rate base assumed is the composite cost of capital (7.52%) from the Hawaiʻi Electric Light 2019 test year rate case Decision and Order No. 37237 in Docket No. 2017-0150; grossed-up for income and revenue taxes (10.348%). (See page 2 of Exhibit 5.) The cost of capital will be based on the weights and rates in effect for rates at the time of the initial MPIR filing.

d. Show net of tax average annual undepreciated investment in allowed Eligible Projects (essentially a rate base calculation with capital investment, accumulated depreciation, accumulated deferred income taxes, and unamortized state investment tax credit) (MPIR Guidelines Sections III.C.2.i and III.C.3.c). (See pages 6 – 9 of Exhibit 5.) Depreciation and taxes will be based on approved rates and regulations in place at the time of the filing (when the Project goes into service and in January in the years following).

The Company proposes that the capital revenue requirements be recovered through the MPIR adjustment mechanism until the revenue requirements are recovered in base rates in a future rate case or general rate setting proceeding. Page 1 of Exhibit 5 calculates the capital revenue requirements at a high level. In the actual MPIR filing, the revenue requirements will be based on actual costs adjusted for the SSM and detailed classification of the costs in the depreciation and tax calculations. An illustration of the MPIR calculation is provided in Exhibit 3.

2. Shared Savings Mechanism

Section 1.9 of the Stage 2 RFP provided the following:

> The SBO 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 SBO Proposal and the actual cost to construct the Project. If the SBO 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 SBO Proposal.

To be consistent with the requirements of the RFP, the Company agrees that capital and O&M cost recovery for the Project will be capped at the amounts proposed in the self-build proposal. However, as allowed in the RFP, the Company proposes a capital cost SSM for the situation where actual costs are less than the approved capped amount, which is intended to be consistent with how an IPP would be compensated, while still providing savings to customers. If the Company completes and operates the Project with total actual costs less than the approved and capped amounts for capital and annual O&M, 90% of the savings would be retained by the Company. This method provides more savings to customers than an IPP would provide under comparable circumstances.

3. Utilization of the MPIR Adjustment Mechanism:

To recap the proposed utilization of the MPIR adjustment mechanism for the Keāhole BESS Project, the Company proposes the following:

a. Revenue requirements associated with the capital costs of the Project flow through the MPIR adjustment mechanism;

b. Depreciation rates applied will be the current approved depreciation rates except for the battery related cost which the Company requests special accounting treatment to depreciated over 20 years (5% annually) in this application. The battery related cost is to be included in FERC plant account 348 – Energy Storage Equipment – Production;

c. Project O&M flow through the MPIR adjustment mechanism.

d. O&M expenses that would be included in the MPIR adjustment mechanism, will be the estimated O&M expenses for the year included in the bid in the RFP, and included in Exhibit 5, page 1. This is the committed O&M expenses for the project.;

(i) Consistent with an IPP, the actual O&M expenses would be at the risk of the company. Actual annual O&M expenses for the Project would be compared with the annual amounts included in the MPIR adjustment for the year. If actual O&M expenses are less that the amounts included in the MPIR adjustment, 90% of the difference, net of taxes, would be a downward adjustment to recorded earnings in determining the Company's earnings for purposes of the earning sharing mechanism. If actual O&M expenses are higher than the amounts included in the MPIR adjustment, the difference, net of taxes, would be an upward adjustment to recorded earnings in determining the Company's earnings for purposes of the earnings sharing mechanism.

The in-service date of Keāhole BESS of no later than December 2022 will trigger, as part of the MPIR process, an adjustment to target revenues by an estimated annualized amount of $2,201,000 beginning January 1, 2023, as illustrated in Exhibit 3, Schedule L. Recovery through the MPIR adjustment mechanism would cease when the revenue requirements are reflected in base rates in a future rate case or general rate setting proceeding.

4. Damages and Penalties

As required by the Stage 2 RFP, committed to in the Company's self-build proposal, and detailed in this Application, the Company proposes that the Project complies with applicable provisions of the ESPPA. Under the circumstances and to the extent that the applicable provisions of the ESPPA would require an IPP to pay damages or penalties to the Company, the Company would also pay such damages and penalties for this Project. In these cases, the Company proposes to return any damages or penalties incurred to customers through the PPAC, similarly to how IPP damages or penalties are currently returned to customers.

IX.

BILL IMPACT

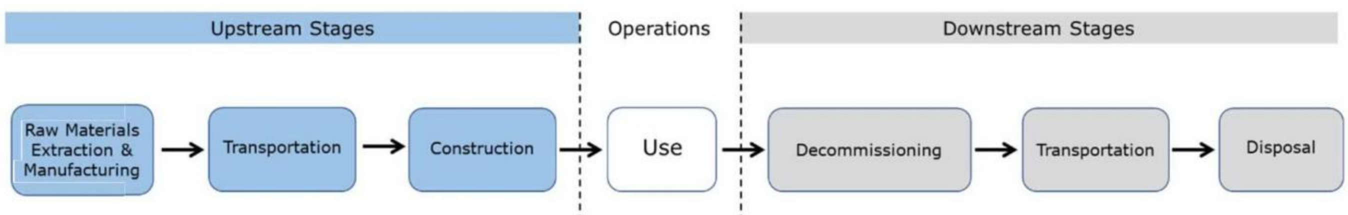
The project costs will have an average $0.86 impact on the typical 500 kWh residential bill over 20 years as shown in Exhibit 5.[32]

X.

GREENHOUSE GAS ANALYSIS

The methodology described below will be utilized to estimate the Greenhouse Gas ("GHG") emissions associated with the Project. Hawaiian Electric will submit the GHG analysis as described below to the Commission by September 30th, 2020. This approach addresses the Upstream, Construction, Operations, and Downstream Stages, as shown in Figure 2.

Figure 2. Stages for Consideration in GHG Emissions Calculation



Potentially significant and reasonably foreseeable equipment, materials and activities are accounted for throughout the Project lifecycle. The following sections provide an overview of the methodology for the Upstream, Operations and Downstream Stages.

A. UPSTREAM STAGES

Upstream Stages include the raw materials extraction, manufacturing, transportation and construction stages of the Project, including GHG emissions that occur off-island. GHG emissions associated with raw material extraction and manufacturing are for equipment and

[32] The projected bill impact calculation is only intended to provide an illustrative example of potential customer bill savings. The specific assumptions and results used in the bill impact calculations are provided in the evaluation attached hereto as Exhibit 5.

materials installed or used during the Project. The GHG emissions for upstream stages also consider total number of pieces of equipment within the project lifetime.

The Transportation and Construction Stages' GHG emissions are calculated using an "inventory approach" where estimated direct GHG emissions from transportation and construction are calculated based on Project- and location-specific data. This includes Upstream and Downstream transportation for material and equipment from manufacturer locations which are mostly off-island to the Project Site and from the Project Site to disposal locations. The Construction Stage includes GHG emissions produced during construction of the Project, including on-road and off-road construction GHG emissions associated with site development, foundation or civil work, and installation of new equipment.

B. OPERATIONS STAGE

Operational Emissions include direct GHG emissions associated with the operation and maintenance of the Project (e.g., the "Operations Stage" shown in Figure 2 of this section). The Operations Stage includes GHG emissions generated from operation and maintenance activities of the equipment and materials in scope for the Project, including onsite energy; material and water use; mobile trips required for worker commute, and maintenance or other operational mobile trips.

C. DOWNSTREAM STAGES

The Downstream Stages include GHG emissions from transportation, distribution, decommissioning and disposal of the proposed equipment at such time the Project is decommissioned after the projected Project lifetime.

D. REPORT

As previously stated, Hawaiian Electric will submit the GHG analysis as described above, to the Commission by September 30, 2020. The estimated GHG emissions result using the methodology described above will be presented in metric tons of Carbon dioxide equivalent (CO_2e) for the Project lifetime. Detailed calculations including assumptions and inputs will be properly documented and included with the GHG analysis report.

XI.

OVERHEAD 69kV INTERCONNECTION

A. HRS § 269-27.5 - PUBLIC HEARING.

The Project includes the installation of a short 69 kV tie-in from the BESS to an adjacent 69 kV substation, all on Company property (See Exhibit 4). A public hearing pursuant to HRS § 269-27.5 is not requested for this Project because there are no existing residential homes in or near the project site. The closest residential area is approximately 0.77 miles away. The 69 kV line extensions will not be visible from the homes, due to the distance and terrain.

B. HRS § 269-27.6(a) OVERHEAD OR UNDERGROUND CONSTRUCTION.

Pursuant to HRS § 269-27.6, whenever a public utility applies for approval to build a new 46 kV or greater transmission line, "either above or below the surface of the ground," the Commission shall determine whether the line shall be "built above or below the surface of the ground." As indicated above, the scope of the Keāhole BESS Project includes the engineering, procurement, and installation of a 69 kV tie-in to an adjacent 69 kV substation. Accordingly, Hawaiʻi Electric Light requests that the Commission approve the proposed 69 kV interconnection for the Project be constructed above the surface of the ground, as described in Section VII.A.1 above. HRS § 269-27.6(a) provides that the Commission shall consider the following factors in making its determination:

> (1) Whether a benefit exists that outweighs the costs of placing the electric transmission system underground;
>
> (2) Whether there is a government public policy requiring the electric transmission system to be placed, constructed, erected, or built

underground, and the governmental agency establishing the policy commits funds for the additional costs of undergrounding;

(3) Whether any governmental agency or other parties are willing to pay for the additional costs of undergrounding;

(4) The recommendation of the division of consumer advocacy of the department of commerce and consumer affairs, which shall be based on an evaluation of the factors set forth under this subsection; and

(5) Any other relevant factors.

Under the circumstances, the factors above support a determination that the proposed 69 kV line be constructed above the ground. With respect to HRS § 269-27.6(a)(1), the benefit of placing the 69 kV line overhead is that the Project will only have a short run from the BESS area to Keāhole Switching Station, thereby reducing the cost of the Project by avoiding the underground costs which are typically 3.5 times more than an overhead connection.

With respect to HRS §§ 269-27.6(a)(2) and 269-27.6(a)(3) the Company is not aware of any governmental public policy requiring the undergrounding of the 69 kV line tap, or agency, or other parties willing to pay for the costs of the 69 kV line tap, or any other factors relevant to the Commission's determination.

In regards to HRS § 269-27.6(a)(4), the Consumer Advocate will have an opportunity to state its position upon completion of its investigation.

Regarding HRS § 269-27.6(a)(5), the Company is not aware of any other relevant factors.

C. NON-TRANSMISSION ALTERNATIVES

The Commission's Inclinations include the following guidance regarding transmission planning and the future development of new transmission Projects on Hawaii's grids:

> **New transmission Projects must consider non-transmission alternatives** – New, replacement or upgrade high-voltage transmission Projects generally represent significant, lumpy capital investments that will be given careful scrutiny. Non-transmission alternatives (NTAs) such as local peaking or back-up generators, energy storage, demand response

> and smart grid resources are technically and commercially available alternatives that must be evaluated as part of any economic justification for new transmission system Projects.[33]

The Keāhole BESS Project is an energy storage project, which will be constructed on Company property, immediately adjacent to an existing substation. The segment of 69kV interconnection that is required to interconnect the Project with Hawaiʻi Electric Light's grid consists of a 15 foot segment of 69kV line. As such, the Project is considered an NTA and the Company submits that no further NTA analysis should be required.

XII.

COMMUNITY OUTREACH

A. COMMUNITY OUTREACH PLAN

As required by the Stage 2 RFP, the Company self-build team developed a community outreach plan, and executed the beginning stages of it while the RFP was in progress. Although initial in-person meetings took place prior to the COVID-19 pandemic, as distancing protocols were put into place, adjustments were made. To keep our community safe but still be able to engage with them on our project and its effects on their community, public meetings were held on community television, and community members were allowed to engage with the presenters through emails. In addition, recorded presentations were provided on the company website. Project Community Outreach plans are provided as Exhibit 8.

B. COMMUNITY COMMENTS

Multiple avenues for participation were provided for community inquiries and feedback. A Company email was made available specific to each project, which was provided on all online public meetings and broadcasts, as well as on the project website. During live TV broadcasts, community members had the opportunity to send questions to project team members via this

[33] Commission's Inclinations at 12.

email, and the presenters answered the questions live on the air. Comments received are provided in Exhibit 9.

Upon the filing of this Application, the Company will provide public notices initiating another 30-day period during which the community will have another opportunity to provide comments.

XIII.

CONCLUSION

Wherefore, Hawaiʻi Electric Light respectfully requests that the Commission issue a D&O:

1. Approving implementation of the Keāhole BESS Project at a total current estimated cost of $16.9 million as further described in Exhibit 2;

2. Approving a commitment of funds in excess of $2,500,000 for the Project, net of customer contributions, as further described in Section VII.A.3 below, pursuant to Paragraph 2.3(g)(2) of the Commission's General Order No. 7, as modified by D&O No. 21002, filed May 27, 2004 in Docket No. 03-0257 ("G.O. 7");

3. Approving the proposed accounting and ratemaking treatment for the Project, as further described in Section VIII, including:

   a. As further described in Exhibit 3, recovery of the Project costs through the MPIR adjustment mechanism established in Order 34514, filed April 27, 2017 in Docket No. 2013-0141, until base rates that reflect the revenue requirements associated with the Project costs take effect in a future rate case or general rate setting proceeding; and

   b. Acknowledgement of the new asset category for accounting purposes, FERC plant account 348 Energy Storage Equipment – Production and the

Company's intent to include the battery related cost in this account; and

c. Depreciation of the battery related cost over 20 years (5% annually);

d. Rate of return as approved in the Company's most recent rate case; and

e. An SSM under which the Company would recover 90% of any cost savings under the approved cost cap.

4. Determining that a public hearing is not required, pursuant to Section 269-27.5 of the Hawai‘i Revised Statutes ("HRS")

5. Approving the construction of the 69kV sub-transmission line for the Project above the surface of the ground, as discussed in Section IX, pursuant to Section 269-27.6(a) of the HRS.

6. Granting Hawai'i Electric Light such other and further relief as may be just and Equitable in the premises.

DATED: Honolulu, Hawai‘i, August 28, 2020.

HAWAIIAN ELECTRIC COMPANY, INC.

By /s/ Joseph P. Viola
Joseph P. Viola
Vice President, Regulatory Affairs

Vice President
Hawai‘i Electric Light Company, Inc.

<u>VERIFICATION</u>

STATE OF HAWAI'I)
) ss.
CITY AND COUNTY OF HONOLULU)

Joseph P. Viola, being first duly sworn, deposes and says: That he is the Vice President – Regulatory Affairs of Hawaiian Electric Company, Inc., and Vice President of Hawai'i Electric Light Company, Inc., Applicant in the above proceeding; that he makes this verification for and on behalf of Hawai'i Electric Light Company, Inc. and is authorized so to do; that he has read the foregoing Application, and knows the contents thereof; and that the same are true of his own knowledge except as to matters stated on information or belief, and that as to those matters he believes them to be true.

/s/ Joseph P. Viola
Joseph P. Viola

Exhibit 1 Energy Storage Power Purchase Agreement Provisions

Introduction

The model ESPPA was drafted and intended to govern the relationship between the Company, as utility operator and purchaser of Energy Storage Services, and a third-party "Seller," as owner and operator of a battery energy storage system and seller of the availability of the Energy Storage Services. Because the self-build option ("SBO") does not fit within this contract paradigm, and the ESPPA was not specifically drafted to address a SBO, Section 1.9 of the Stage 2 RFP,[1] which sets forth the procedures for self-build proposals, recognized that the SBO would not be required to enter into the model ESPPA; rather, the SBO would be asked to commit to comply with specific ESPPA provisions set forth in Appendix G Attachment 1, Self-Build Option Team Certification Form:

> . . . Except where specifically noted, an SBO Proposal must adhere to the same price and non-price Proposal requirements as required of all Proposers, as well as certain PPA requirements, such as milestones and liquidated damages, as described in Appendix G. The non-negotiability of the Performance Standards shall apply to any SBO to the same extent it would for any other Proposal. Notwithstanding the fact that it will not be required to enter into an RDG PPA or ESPPA with the Company, a Self-Build Proposer will be required to note its exceptions, if any, to the RDG PPA and/or ESPPA in the same manner required of other Proposers, and will be held to such modified parameters if selected. In addition to its Proposal, the Self-Build Team will be required to submit Appendix G Attachment 1, Self-Build Option Team Certification Form, acknowledging . . . adherence to PPA terms and milestones required of all proposers and the SBO's proposed cost protection measures.
>
> The cost recovery methods between a regulated utility SBO 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

[1] See Docket 2017-0352, *Request for Proposals for Variable Renewable Dispatchable Generation and Energy Storage Island of Hawai'i*, Book 5 of 7, filed August 22, 2019.

> initial evaluation of the price related criteria on a 'like' basis through comparative analysis. (Emphasis in original).

Section 3.8.4 of the Stage 2 RFP similarly notes that the SBO will not execute the model ESPPA but would be held to the provisions stated in the Self Build Option Certification, subject to any proposed SBO modifications, and as adjusted with the approval of the Commission:

> If selected, a Self-Build Proposer will not be required to enter into a PPA or ESPPA with the Company. However, the Self-Build Proposer will be held to the proposed modifications to the RDG PPA and/or ESPPA, if any, it submits as part of the SBO in accordance with <u>Section 3.8.7</u>. Moreover, the SBO will be held to the same performance metrics and milestones set forth in the RDG PPA and/or ESPPA to the same extent as all Proposers, as attested to in the SBO's <u>Appendix G, Attachment 1, Self Build Option Certification</u> submittal. If liquidated damages are assessed, they will be paid from shareholder funds and returned to customers through the Purchased Power Adjustment Clause ("PPAC") or other appropriate rate adjustment mechanisms.
>
> To retain the benefits of operational flexibility for a Company-owned facility, the SBO 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 PPA with PUC approval. (Emphasis in original).

Further recognizing that the SBO does not fit squarely within the model ESPPA contract paradigm, the Self-Build Option Team Certification specifically acknowledged that ESPPA terms related to commercial and legal interactions between "Seller" and the Company were not applicable:

> The SBO Proposal will be consistent with the scope of work and responsibilities of the "Seller" under the terms of the applicable Model PPA <u>excluding inapplicable terms related to commercial and legal interactions between the Seller and the Company</u>.[2]

[2] Self Build Option Team Certification, Section D.1. (emphasis added).

The Self Build Option Team Certification further served to identify the particular ESPPA provisions that would apply to the Proposal. Specifically, pursuant to the Self Build Option Team Certification, the Self Build Team agreed that the SBO Facility will be designed and constructed to:

- Achieve the Performance Standards identified in Section 3 - Performance Standards, in Attachment B of the applicable Model [ESPPA] 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);[3]
- Meet the performance metrics as specified in . . . Article 4 of the ESPPA . . . [f]or 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;[4]
- Pass the Acceptance Test specified in Attachment N - Acceptance Test General Criteria of the applicable Model . . . ESPPA;[5]
- Pass the Control System Performance Test specified in Attachment O – Control System Acceptance Test Criteria of the applicable Model . . . ESPPA;[6]
- If applicable, pass the On-line Performance Test specified in . . . Attachment T - Facility Tests of the Model ESPPA;[7] and
- Meet the project milestones identified in the SBO Proposal no later than the dates specified therein, which shall be consistent with the guaranteed project milestones required in Attachment K - Guaranteed Project Milestones of the Model . . . ESPPA (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.[8]

In addition, under the Self Build Option Team Certification, the Self Build Team further agreed that the Company:

- [Will] achieve the reporting milestones identified in the SBO

[3] Self Build Option Team Certification, Section D.2.a.
[4] *Id.* at Section D.2.b.b.3.
[5] *Id.* at Section D.2.c.
[6] *Id.* at Section D.2.d.s
[7] *Id.* at Section D.2.e.
[8] *Id.* at Section D.2.g.

Proposal no later than the dates specified therein, which shall be consistent with the reporting milestones required in Attachment L - Reporting Milestones of the Model . . . ESPPA (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;[9]

- Will be subject to the applicable liquidated damages for the . . . ESPPA 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. Notice of any liquidated damages assessed and amounts of such liquidated damages will be provided to PUC and Consumer Advocate;[10] and
- Will provide annual report to PUC and Consumer Advocate on performance metrics.[11]

Finally, the Self Build Option Team Certification contemplated that the applicable ESPPA terms would be reaffirmed in the GO7 application for any selected SBO project and the associated approval order, as is being done in this Application.[12]

Thus, consistent with the above, the Self Build Team in its Proposal agreed to: (1) meet or achieve specific ESPPA performance standards, metrics, tests, and project milestones, (2) be subject to applicable liquidated damages, (3) provide notice of any liquidated damages assessed and amounts of such liquidated damages to the Commission and Consumer Advocate, (4) provide notice of completion of project and reporting milestones and any delay to the Commission and Consumer Advocate, and (5) provide an annual report to the Commission and Consumer Advocate on performance metrics.[13]

In addition, and as required by the Stage 2 RFP, the Self Build Team noted certain

[9] *Id.*, Section D.2.h.
[10] *Id.*, Section D.2.i.
[11] *Id.*, Section D.2.k.
[12] *Id.*, Section D.2.j.
[13] *See* Self Build Option Team Certification.

inapplicable ESPPA terms and exceptions in Attachment 2.4.1 to its Proposal. In particular, Attachment 2.4.1. identified ESPPA provisions that were inapplicable because the SBO and the Company were the "same legal entity" and because the provisions were not applicable to the SBO (e.g., because the provisions applied to solar projects).[14] The Company acknowledges that the list of inapplicable terms and exceptions set forth in Attachment 2.4.1. is not exhaustive as it does not include a number of provisions that are not applicable to the Project, as reflected in Exhibit 1; however, the Company does not believe that this oversight should have a material impact on this Application, especially where the Stage 2 RFP makes clear that the SBO will not be required to enter into the ESPPA and where the Self Build Option Team Certification acknowledged and agreed that terms of the ESPPA related to commercial and legal interactions between the Seller and the Company are inapplicable and excluded.[15]

Compensation to Customers

For terms discussing payment of damages or penalties, see Section VIII of the Application, which discusses how these penalties and damages will be provided to Customers from the Company. In connection with the payment of such penalties or damages and for purposes of this Exhibit 1, "Lump Sum Payment" shall be defined as the net present value of the total actual revenue requirements divided by the 240 month lifecycle of the Project. Total actual revenue requirements shall be the sum of the capital revenue requirements based on actual project costs (adjusted for the project capital cost cap and the approved shared savings mechanism) and the proposed O&M revenue requirements.

Articles and Attachments

[14] Attachment 2.4.1 also referenced provisions the SBO expected would be incorporated into the GO7 application process.
[15] Self Build Option Team Certification, Section D.1.

This Exhibit 1 reflects for convenience, a consolidation of applicable provisions of the ESPPA related to performance standards, metrics, tests, project milestones, and liquidated damages that the Company has agreed will govern the Project, as set forth in and subject to the Self Build Option Team Certification. As discussed above, because the SBO does not fit the model ESPPA contract paradigm, the ESPPA language itself in turn does not always align with a SBO project. As such, in addition to excluding inapplicable terms, in some areas, the Company has edited ESPPA provisions for application to a SBO while attempting to retain the original intent of the provision; in other areas, for clarity, the Company will note how the Company intends the provisions would be implemented for a SBO – for example, for all sections in Exhibit 1 providing for an interaction between "Seller" and "Company," such interaction shall be incorporated into the Company's internal project management, operations, and/or oversight processes. Further, the daily delay LD amount has been calculated and entered in Exhibit 1, while remaining technical parameters to be determined through the final design of the Project remain blank. Finally, similar to the independent power producers, Company may, with approval from the IO, adjust interim milestone dates based on the results of the Interconnection Requirements Study which is ongoing.

Article 4: COMPENSATION; PERFORMANCE METRICS[16]

4.3 Capacity Performance Metric.

(a) Capacity Test and Liquidated Damages. During commissioning, and for each Measurement Period following the Commercial Operations Date, the Facility shall be required to complete a Capacity Test, as more fully set forth in **Attachment T** (Facility Tests) to this

[16] Unless defined herein, capitalized terms shall have the meaning stated in the model ESPPA.

Agreement. For each Measurement Period for which the Facility fails to demonstrate that it satisfies the Capacity Performance Metric, Seller shall pay, and Company shall accept, as liquidated damages for such shortfall, the amount set forth in the following table (on a progressive basis) upon proper demand at the end the Measurement Period in question:

Capacity Ratio	**Liquidated Damage Amount**
Tier 1 95.0% - 99.9%	For each one-tenth of one percent (0.001) that the Capacity Ratio is below 100% and is above 94.9%, an amount equal to one-tenth of one percent (0.001) of the Lump Sum Payment for the Measurement Period in question; plus
Tier 2 85.0% - 94.9%	For each one-tenth of one percent (0.001) that the Capacity Ratio is below 95% and is above 84.9%, an amount equal to one and a half-tenths of one percent (0.0015) of the Lump Sum Payment for the Measurement Period in question; plus
Tier 3 75.0% - 84.9%	For each one-tenth of one percent (0.001) that the Capacity Ratio is below 85% and is above 74.9%, an amount equal to two-tenths of one percent (0.002) of the Lump Sum Payment for the Measurement Period in question; plus
Tier 4 60.0% - 74.9%	For each one-tenth of one percent (0.001) that the Capacity Ratio is below 75% and is above 59.9%, an amount equal to two and a half-tenths of one percent (0.0025) of the Lump Sum Payment for the Measurement Period in question; plus

Tier 5 50.0% - 59.9%	For each one-tenth of one percent (0.001) that the Capacity Ratio is below 60% and is above 49.9%, an amount equal to three-tenths of one percent (0.003) of the Lump Sum Payment for the Measurement Period in question; plus
Tier 6 49.9% and below ("**Lowest Capacity Bandwidth**")	For each one-tenth of one percent (0.001) that the Capacity Ratio is below 50%, an amount equal to three and a half-tenths of one percent (0.0035) of the Lump Sum Payment for the Measurement Period in question.

For purposes of determining liquidated damages under this **Section 4.3(a)** (Capacity Test and Liquidated Damages), the starting and end points for the duration of the period that the Facility discharges shall be rounded to the nearest MWh. Each Party agrees and acknowledges that (i) the damages that Company would incur if the Seller fails to achieve the Capacity Performance Metric for a Measurement Period would be difficult or impossible to calculate with certainty and (ii) the aforesaid liquidated damages are an appropriate approximation of such damages.

EXAMPLE: The following is an example calculation of liquidated damages for the Capacity Performance Metric and is included for illustrative purposes only. Assume the following:

- The Maximum Rated Output for the Facility is 25 MW.
- A Capacity Test was conducted and the Facility was measured to have discharged 97.5 MWh
- Contract Capacity = 25 MW x 6 hours = 150 MWh

- Capacity Ratio = MWh Discharged ÷ Contract Capacity = 97.5 MWh ÷ 150 MWh = 0.65
- LD = [((1 – 0.950) x 1) + ((0.950 – 0.850) x 1.5) + ((0.850 – 0.750) x 2 + ((0.750 – 0.65) x 2.5] x Lump Sum Payment for the Measurement Period in question
- = 0.65 x Lump Sum Payment for the Measurement Period in question

4.4 Equivalent Availability Factor Performance Metric.

(a) Annual Equivalent Availability Factor and Liquidated Damages. For each Measurement Period following the Commercial Operations Date, an Annual Equivalent Availability Factor ("**Annual EAF**") shall be calculated as set forth in **Attachment U** (Annual Equivalent Availability Factor). If the Annual EAF for such Measurement Period is less than **97%**[17] (the "**EAF Performance Metric**"), Seller shall pay, and Company shall accept, as liquidated damages for such shortfall, the amount set forth in the following table (on a progressive basis) upon proper demand at the end the current Measurement Period:

Annual Equivalent Availability Factor	**Liquidated Damage Amount**
Tier 1 85.0% - 96.9%	For each one-tenth of one percent (0.001) by which the Annual EAF falls below 97% but equal to or above 85%, an amount equal to one-tenth of one percent (0.001) of the Lump Sum Payment for the Measurement Period in question; plus

[17] The Self Build Team proposes to change this value from 97% to 96%, to adequately account for maintenance outage requirements. This change would also affect the Tier 1 parameters listed in the Table included in this Section 4.4.

Tier 2 80.0% - 84.9%	For each one-tenth of one percent (0.001) by which the Annual EAF falls below 85% but equal to or above 80%, an amount equal to two-tenths of one percent (0.002) of the Lump Sum Payment for the Measurement Period in question; plus
Tier 3 75.0% - 79.9%	For each one-tenth of one percent (0.001) by which the Annual EAF falls below 80% but equal to or above 75%, an amount equal to three-tenths of one percent (0.003) of the Lump Sum Payment for the Measurement Period in question; plus
Tier 4 Below 75.0%	For each one-tenth of one percent (0.001) by which the Annual EAF falls below 75%, an amount equal to four-tenths of one percent (0.004) of the Lump Sum Payment for the Measurement Period in question.

Such liquidated damages will be passed through to customers through the Company's Power Purchase Adjustment Clause.

For purposes of determining liquidated damages under this **Section 4.4(a)** (Annual Equivalent Availability Factor and Liquidated Damages), the Annual EAF for the Measurement Period in question shall be rounded to the nearest one-tenth of one percent (0.001). Each Party agrees and acknowledges that (i) the damages that Company would incur if the Seller fails to achieve the EAF Performance Metric for a Measurement Period would be difficult or impossible to calculate with certainty and (ii) the aforesaid liquidated damages are an appropriate approximation of such damages.

4.5 Equivalent Forced Outage Factor Performance Metric.

(a) Annual Equivalent Forced Outage Factor and Liquidated Damages. For each Measurement Period following the Commercial Operations Date, the Facility shall maintain an Annual Equivalent Forced Outage Factor ("**Annual EFOF**") of not more than 4% (the "**EFOF Performance Metric**") as calculated as set forth in **Attachment V** (Annual Equivalent Forced Outage Factor). If the EFOF for such Measurement Period exceeds the EFOF Performance Metric, Seller shall pay, and Company shall accept, as liquidated damages for exceeding the EFOF Performance Metric, the amount set forth in the following table (on a progressive basis) upon proper demand by the Company at the end of the Measurement Period in question:

Annual Equivalent Forced Outage Factor	**Liquidated Damage Amount**
0.0% - 4.0%	-0-
4.1% - 6.9%	For each one-tenth of one percent (0.001) that the Annual EFOF is above 4.0% but less than 7.0%, an amount equal to two-tenths of one percent (0.002) of the Lump Sum Payment for the Measurement Period in question; plus
7.0% and above	For each one-tenth of one percent (0.001) that the Annual EFOF is above 6.9%, an amount equal to four-tenths of one percent (0.004) of the Lump Sum Payment for the Measurement Period in question.

Such liquidated damages will be passed through to customers through the Company's Power Purchase Adjustment Clause.

For purposes of determining liquidated damages under this **Section 4.5(a)** (Annual Equivalent Forced Outage Factor and Liquidated Damages), the Annual EFOF for the Measurement Period in question shall be rounded to the nearest one-tenth of one percent (0.001). Each Party agrees and acknowledges that (i) the damages that Company would incur if the Seller fails to achieve the EFOF Performance Metric for a Measurement Period would be difficult or impossible to calculate with certainty and (ii) the aforesaid liquidated damages are an appropriate approximation of such damages.

For example, if the Annual EFOF was 4.1% as calculated in the example in **Attachment V** (Annual Equivalent Forced Outage Factor) attached hereto and the Lump Sum Payment for the Measurement Period in question is $1,000,000, the liquidated damages would be $2,000, calculated as follows:

- 4.1% - 4.0% = 0.1%
- $1,000,000 x .002 = $2,000
- $2,000 x 1 = $2,000

4.6 Fast Frequency Response Performance Metric.

(a) Fast Frequency Response Criteria and Liquidated Damages. Following the Commercial Operations Date, the Facility shall respond appropriately to frequency disturbances in the Company System by operating in a manner consistent with standards and parameters established for Fast Frequency Response. With respect to such frequency disturbances in the Company System, the Facility shall be required to meet all of the following minimum frequency performance criteria (collectively, the "**Fast Frequency Response Performance Metric**"):

(i) The time between a step change in frequency and the response is no more than 1.3 times the target reaction time;

(ii) The resource achieves at least 63% of the new steady state active power output within the rise time;

(iii) The resource achieves at least 70% of the new steady state active power target within the settling time;

(iv) Overshoot does not exceed 5% of the final steady state active power; and

(v) The new steady-state active power output is within the settling band.

Company will review historical operational data to determine the Facility's fast frequency response following disturbances and satisfaction of the Fast Frequency Response Performance Metric. In accordance with **Section 8(v)** (Data Collection) of **Attachment B** (Facility Owned by Seller), Seller shall provide such high resolution data from the Facility requested by Company to assist in the review. To the extent the historical operational data is insufficient or otherwise lacking for purposes of determining the Facility's satisfaction of the Fast Frequency Response Performance Metric, Company shall review Facility's performance under structured test conditions no less than once per Contract Year.

After the first Contract Year:

(1) for each instance of the Facility failing to satisfy the Fast Frequency Response Performance Metric, Seller shall pay, and Company shall accept, as liquidated damages for such failure, an amount equal to **25%** of the monthly Lump Sum Payment upon proper demand by Company; and

(2) in the event poor Facility fast frequency response performance requires disconnection from the Company System, as determined by Company in its sole discretion (e.g., in the event a Facility response to Company System frequency outside of the FFR deadband

contributes to frequency error or worsens the disturbance), Seller shall pay and Company shall accept, as liquidated damages for such underperformance, an amount equal to **100%** of the monthly Lump Sum Payment upon proper demand by Company, and Seller shall continue to pay an amount equal to the monthly Lump Sum Payment as liquidated damages for every month the Facility remains disconnected from the Company System to allow Seller to perform corrective actions on the Facility to Company's reasonable satisfaction.

Such liquidated damages will be passed through to customers through the Company's Power Purchase Adjustment Clause.

Company agrees that, when evaluating performance under this **Section 4.6** (Fast Frequency Response Performance Metric), the available State of Charge shall be taken into consideration and Seller shall not be held to the criteria set forth in this **Section 4.6** (Fast Frequency Response Performance Metric) if there is insufficient charged capacity available for the appropriate response.

(b) Performance Deficiencies. With respect to any Facility response under this **Section 4.6** (Fast Frequency Response Performance Metric), Company will notify Seller of any discrepancies in the Facility response, and Seller shall respond to and cure all such performance deficiencies in accordance with **Section 1(j)** (Demonstration of Facility) of **Attachment B** (Facility Owned by Seller).

4.7. Limitation on Liquidated Damages.

(b) Limitation on Liquidated Damages. Notwithstanding any other provision of this Agreement to the contrary, the aggregate liquidated damages paid by Seller during each Contract Year for the Performance Metrics LDs, shall not exceed the total of twelve (12) monthly Lump Sum Payments.

Article 8: CHARGING ENERGY OBLIGATIONS

Except as otherwise set forth in this **Article 8** (Charging Energy Obligations) or as expressly set forth in this Agreement, following the Commercial Operations Date, Company shall be responsible for and bear the cost of delivering all of the Charging Energy for the Facility to the Point of Interconnection. So long as the State of Charge is less than 100%, Seller shall take all actions necessary to accept the Charging Energy, as delivered by Company by manual dispatch or automatic signals, at and from the Point of Interconnection as part of making available to Company the Facility's Energy Storage Services in accordance with the terms of this Agreement and Company tariffs, including, without limitation, maintenance, repair or replacement of equipment in Seller's possession or control used to deliver the Charging Energy to the Facility. Seller shall only use the Charging Energy for Company's benefit in accordance with the terms of this Agreement.

Article 11: CONSTRUCTION PERIOD AND MILESTONES

11.2 Monthly Progress Report[18].

Commencing upon the PUC Approval Date, Seller shall submit to Company, on the tenth (10th) Business Day of each calendar month until the Commercial Operations Date, a progress report for the prior month in a form acceptable to Company. These progress reports shall notify Company of the current status of each Construction Milestone. Seller shall include in any Monthly Progress Report a list of all letters, notices, applications, approvals, authorizations and filings referring or relating to Governmental Approvals, and shall provide any such documents as may be reasonably requested by Company. In addition, Seller shall advise Company, as soon as

[18] Progress reports to be provided internally, according to Company's established project management and governance policies.

reasonably practicable, of any problems or issues of which Seller is aware which could materially impact its ability to timely achieve any Construction Milestone. Seller shall provide Company with any requested documentation to support the achievement of an applicable Construction Milestone within ten (10) Business Days of receipt of such request from Company. Upon the occurrence of a Force Majeure event, Seller shall also comply with the requirements of **Section 17.4** (Satisfaction of Certain Conditions) to the extent such requirements provide for communications to Company beyond those required under this **Section 11.2** (Monthly Progress Report).

11.3 Remedial Action Plan[19].

In the event Seller does not timely achieve a Reporting Milestone, Seller shall submit to Company, within ten (10) Business Days of any such missed Reporting Milestone date, a remedial action plan which shall provide a detailed description of Seller's course of action and plan to achieve (a) the missed Reporting Milestone within ninety (90) Days of the missed Reporting Milestone date; and (b) all subsequent Construction Milestones; provided, that delivery of any remedial action plan shall not relieve Seller of its obligation to timely achieve such Construction Milestones.

11.4 Milestone Dates

Seller shall achieve each Guaranteed Project Milestone Date or Reporting Milestone Date, subject (to the extent applicable) to the following extensions:

[19] Action plans to be provided internally, according to Company's established project management and governance policies.

(a) if the PUC Approval Order[20] Date[21] occurs more than one hundred eighty (180) Days after the date the Company files its Application for Approval to Commit Funds in Excess of $2,500,000 for the Purchase and Installation of Item HZ.005027 Keāhole Battery Energy Storage System Project, and to Recover Costs through the Major Project Interim Recovery Adjustment Mechanism ("GO7 Application"), Seller and Company shall be entitled to an extension of the Guaranteed Project Milestone Dates, Reporting Milestone Dates, Seller's Conditions Precedent Dates and Company Milestone Dates equal to the number of Days that elapse between the end of the aforesaid 180-Day period and the PUC Approval Order Date; provided, that in no event will the Guaranteed Commercial Operations Date be extended beyond April 2024;

(b) if the failure to achieve a Construction Milestone by the applicable Guaranteed Project Milestone Date or Reporting Milestone Date is the result of Force Majeure (which, for purposes of this **Section 11.4(b)** excludes any delay in obtaining the PUC Approval Order because that contingency is addressed in **Section 11.4(a)** above), and if and so long as the conditions set forth in **Section 17.4** (Satisfaction of Certain Conditions) are satisfied, such Guaranteed Project Milestone Date or Reporting Milestone Date shall be extended by a period equal to the lesser of three hundred sixty-

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[20] For purposes of this Exhibit 1, "PUC Approval Order" shall mean an order from the PUC that does not contain terms and conditions deemed to be unacceptable by Company, and is in a form deemed to be reasonable by Company, in its sole, but nonarbitrary, discretion, ordering: (i) approval of the GO7 Application; (ii) approval of the implementation of the Keāhole BESS Project at a total current estimated cost of $16.9 million as further described in Exhibit 2; (iii) approval of a commitment of funds in excess of $2,500,000 for the Project, net of customer contributions, pursuant to GO7; (iv) approval of the proposed accounting and ratemaking treatment for the Project, as further described in the GO7 Application; (v) determination that a public hearing is not required, pursuant to HRS Section 269-27.5; (vi) approval of the construction of the 69kV sub-transmission line for the Project above the surface of the ground, pursuant to HRS Section 269-27.6(a); and (vii) approval of the terms set forth in this Exhibit 1.

[21] If the Company determines, not later than thirty-five (35) Days after the issuance of a PUC order approving the GO7 Application, that the conditions for a PUC Approval Order have been satisfied, the date of the issuance of the PUC Approval Order shall be the "PUC Approval Order Date."

five (365) Days or the duration of the delay caused by the Force Majeure; or

(c) if the failure to achieve a Guaranteed Project Milestone by the applicable Guaranteed Project Milestone Date is the result of any failure by Company in the timely performance of its obligations under this Agreement, including achievement of its Company Milestones by the Company Milestone Dates as set forth on **Attachment K-1** (Seller's Conditions Precedent and Company Milestones), as such dates may be extended in accordance with **Section 11.4** (Milestone Dates) and **Section 11.5** (Company Milestones), Seller shall, provided Seller has satisfied Seller's Conditions Precedent set forth in **Attachment K-1** (Seller's Conditions Precedent and Company Milestones) by the respective Seller's Conditions Precedent Date set forth in said **Attachment K-1**, be entitled to an extension of such Guaranteed Project Milestone Date equal to the duration of the period of delay directly caused by such failure in Company's timely performance. Such extension on the terms described above shall be Seller's sole remedy for any such failure by Company. For purposes of this **Section 11.4(c)**, Company's performance will be deemed to be "timely" if it is accomplished within the time period specified in this Agreement with respect to such performance or, if no time period is specified, within a reasonable period of time. If the performance in question is Company's review of plans, the determination of what is a "reasonable period of time" will take into account Company's past practices in reviewing and commenting on plans for similar facilities.

11.5 Company Milestones.

Company's obligation to achieve the Company Milestones is contingent upon Seller completing the Seller's Conditions Precedent set forth in **Attachment K-1** (Company Milestones and Seller's Conditions Precedent). Company shall achieve each of the Company Milestones by the date set forth for such Company Milestones in **Attachment K-1** (Seller's Conditions Precedent and Company Milestones) of this Agreement (each such date, a "**Company Milestone Date**"), as such date may be extended in accordance with **Section 11.4** (Milestone Dates) and this **Section 11.5** (Company Milestones); provided, however in the event Seller does not complete a Seller's Condition Precedent on or before the applicable date set forth in **Attachment K-1** (Seller's Conditions Precedent and Company Milestones) (each such date, a "**Seller's Conditions Precedent Date**"), subject to the extensions set forth in **Section 11.4** (Milestone Dates), Company shall be entitled to an extension as follows: (i) for the commencement of Acceptance Testing, the new Company Milestone Date shall be as set forth in clause "(gg)" of **Section 2(f)(i)** of **Attachment G** (Company-Owned Interconnection Facilities); and (ii) for any other Company Milestone Date, the extension shall be for the period of time reasonably necessary to meet any such Company Milestone Date adversely affected by Seller's failure, which extension shall be no shorter than a day-for-day extension.

11.6 Damages.

(a) Daily Delay Damages.

(i) If a Guaranteed Project Milestone (other than Commercial Operations) has not been achieved by the applicable Guaranteed Project Milestone Date, as extended as provided in **Section 11.4** (Milestone Dates), Company shall collect and Seller shall pay liquidated damages in the amount of $3,333.33 ("**Daily Delay Damages**") for each Day following the applicable Guaranteed Project Milestone Date, as extended in accordance with **Section 11.4** (Milestone Dates); provided, however, that the number of Days for which Company shall collect and Seller shall pay Daily Delay Damages for a failure to achieve a Guaranteed Project Milestone by the Guaranteed Project Milestone Date shall not exceed sixty (60) Days for each such missed Guaranteed Project Milestone Date (the "**Construction Delay LD Period**"). **[Note: Daily Delay Damages = Contract Capacity x $50/kW ÷ 180 Days]**

(ii) If the Commercial Operations Date has not been achieved by the Guaranteed Commercial Operations Date, as extended as provided in **Section 11.4** (Milestone Dates), in addition to any Daily Delay Damages collected pursuant to **Section 11.6(a)(i)**, Company shall collect and Seller shall pay Daily Delay Damages for each Day following the Guaranteed Commercial Operations Date, as such date may be extended in accordance with **Section 11.4** (Milestone Dates); provided that the number of Days for which Company shall collect and Seller shall pay Daily Delay Damages for failing to timely achieve the Commercial Operations Date shall not exceed one hundred eighty (180) Days (the "**COD Delay LD Period**").

Article 12

DISPATCHING AND CHARGING THE FACILITY; SCHEDULING

12.1 Dispatching and Charging the Facility.

(a) Company's Exclusive Rights. Company shall have the exclusive right, through supervisory equipment or otherwise, to direct and control the provision of all aspects of the Energy Storage Services, at any time, as it deems appropriate in its reasonable discretion, subject only to and consistent with Good Engineering and Operating Practices, the operational and performance standards requirements set forth in **Section 3** (Performance Standards) of **Attachment B** (Facility Owned by Seller), and Seller's maintenance schedule determined in accordance with **Section 12.2** (Seller's Maintenance Schedule) ("**Company Dispatch/Charge**"). Seller shall make the full capability of the Facility available for Company Dispatch/Charge. Company Dispatch/Charge will be under the direction of the Company System Operator or by remote computerized control by the Energy Management System provided in **Section 1(g)** (Active Power Control Interface) of **Attachment B** (Seller's Facility), in each case at Company's reasonable discretion, and in accordance with the Performance Standards (in particular, the frequency response). This includes specification of the frequency response mode. When in Fast Frequency Response mode, the Facility charging/discharging will be determined in accordance with the agreed parameters for maintaining a state of charge.

(b) Failure to Comply; Seller-Attributable Unavailability. Company may require deration or outage in response to the Facility's failure to comply with Company Dispatch/Charge or to any conditions of Seller-Attributable Unavailability. A deration or outage required by Company pursuant to the preceding sentence shall be considered an Unplanned Deration and shall "count against" Seller for the purpose of calculating the Annual EAF and Annual EFOF until the conditions that led to the deration or outage are resolved by Seller and Seller notifies Company of same. If, after such notification, Company attempts to dispatch the Facility and determines that such conditions that led to the deration or outage are not resolved, all time from the notice of resolution to actual resolution shall be revised as continuance of the deration or outage. If Seller requests confirmation from Company that Seller's actions to resolve such conditions that led to the deration or outage were successfully completed, then Company shall use reasonable efforts to respond to such request within three (3) Business Days in writing (with Email being acceptable) to allow Seller the opportunity to take further appropriate corrective actions if needed.

12.2 Seller's Maintenance Schedule.[22]

(a) Quarterly Schedule. By each March 1, June 1, September 1 and December 1 (as applicable, subsequent to the Commercial Operations Date), Seller shall provide to Company, in the form requested by Company, a projection of maintenance outages and estimated reductions in capacity for the next calendar quarter. Seller shall provide Company with prompt written notice of any deviation from its quarterly maintenance schedule but in any case, Seller shall provide such written notice not less than one (1) week prior to commencing any such rescheduled maintenance event. During any scheduled or rescheduled maintenance event, Seller shall provide updates to Company's operating personnel in the event there are any delays or changes to the proposed schedule, and shall promptly respond to any requests from Company for updates regarding the status of such maintenance event.

(b) Annual Schedule. By each June 30 subsequent to the Commercial Operations Date, Seller shall submit to Company, in the form requested by Company, a schedule of maintenance outages which will reduce the capacity of the Facility by **[Drafting Note: the lower of one (1) MW or 10%]** or more for the next one-year period, beginning with January of the following year. Such annual schedule shall state the proposed dates and durations of scheduled maintenance, the scope of work for the maintenance and the estimated reductions in capacity for each projected maintenance event. Company shall review the maintenance schedule for the one-year period and inform Seller in writing no later than December 1 of the same year of Company's concurrence or requested revisions, which Seller shall agree to unless, in Seller's judgment, such proposed revisions will void or violate any warranties of equipment that is part of, or used in connection with, the Facility or violate any long-term service agreement with

[22] Notification, scheduling, and execution of system maintenance plans to be conducted according to Company's established internal policies.

respect to such equipment; provided, that, in each such case, Seller shall promptly notify Company thereof, and Seller and Company shall endeavor to reach a mutually satisfactory resolution of the matter in question.

(c) **Scheduling of Maintenance Outages.** Seller shall coordinate the scheduling of all planned maintenance outages with the Company to ensure all such outages occur at times when Company's System is at low risk, as determined by Company, for requiring any Fast Frequency Response from the Facility. Seller shall also work with Company to limit maintenance outages, when possible, to partial outages of the Facility instead of a total Facility outage.

12.3 Seller's Notification Obligations.

When Seller learns that any of its equipment will be removed from or returned to service, and any such removal or return may affect the ability of the Facility to make the Energy Storage Services available to Company, Seller shall notify Company as soon as practicable and any unit shut-down shall be coordinated with Company in advance to the extent practicable.

12.4 Outage Costs.

Seller shall use commercially reasonable efforts to mitigate any losses of Energy due to an outage such that losses are limited to the Facility's standby consumption, specifically, no more than [ ][23] kWh per twenty four (24) hours of outage duration.

[23] Acceptable standby consumption limits to be determined upon final design.

Article 17 Satisfaction of Certain Conditions

17.1 Definition of Force Majeure.

The term "**Force Majeure**" as used in this Agreement means any occurrence that:

(a) In whole or in part delays or prevents a Party's performance under this Agreement;

(b) Is not the direct or indirect result of the fault or negligence of that Party;

(c) Is not within the control of that Party notwithstanding such Party having taken all reasonable precautions and measures in order to prevent or avoid such event; and

(d) The Party has been unable to overcome by the exercise of due diligence.

17.2 Events That Could Qualify as Force Majeure.

Subject to the foregoing, events that could qualify as Force Majeure include, but are not limited to, the following:

(a) acts of God, flooding, lightning, landslide, earthquake, fire, drought, explosion, epidemic, quarantine, storm, hurricane, tornado, volcano, other natural disaster or unusual or extreme adverse weather-related events;

(b) war (declared or undeclared), riot or similar civil disturbance, acts of the public enemy (including acts of terrorism), sabotage, blockade, insurrection, revolution, expropriation or confiscation; or

(c) except as set forth in **Section 17.3(i)**, strikes, work stoppage or other labor disputes (in which case the affected Party shall have no obligation to settle the strike or labor dispute on terms it deems unreasonable).

17.3 Exclusions From Force Majeure.

Force Majeure, however, does not include any of the following:

(a) any acts or omissions of any third party, including, without limitation, any vendor, materialman, customer, or supplier of Seller, unless such acts or omissions are themselves caused by an event of Force Majeure;

(b) any full or partial reduction in the availability of the Facility to provide the Energy Storage Services in response to Company Dispatch/Charge that is caused by or arises from either (i) a mechanical or equipment breakdown, or other mishaps, events or conditions attributable to normal wear and tear, unless such mishap is caused by Force Majeure; or (ii) any action or inaction of a third party, including but not limited to any vendor or supplier of the Seller or Company, except to the extent such action or inaction is due to Force Majeure;

(c) changes in market conditions that affect the cost of the Seller's supplies, or that otherwise render this Agreement uneconomic or unprofitable for the Seller;

(d) Seller's inability to obtain Governmental Approvals or Land Rights for the construction, ownership, operation or maintenance of the Facility, or Seller's loss of any such Governmental Approvals or Land Rights once obtained;

(e) Seller's inability to obtain sufficient fuel, power or materials to operate the Facility, except if Seller's inability to obtain sufficient power or materials is caused solely by an event of Force Majeure;

(f) Seller's failure to obtain additional funds, including funds authorized by a state or the federal government or agencies thereof, to supplement the payments made by Company pursuant to this Agreement;

(g) a forced outage except where such forced outage is caused by an event of Force

Majeure;

(h) litigation or administrative or judicial action pertaining to Seller's interest in this Agreement, the Site, the Facility, the Land Rights, any Governmental Approvals, or the construction, ownership, operation or maintenance of the Facility, the Company-Owned Interconnection Facilities or the Company System;

(i) A strike, work stoppage, or labor dispute limited only to any one or more of the Indemnified Seller Parties or any other third party employed by Seller to work on the Facility.

17.4 Satisfaction of Certain Conditions.

Subject to **Article 11** (Construction Period and Milestones), if, because of Force Majeure, either Party is unable to perform its obligations under this Agreement, such Party shall be excused from whatever performance is affected by the Force Majeure only to the extent so affected; provided:

(a) the non-performing Party gives the other Party, no more than five (5) Days after the non-performing Party becomes aware or should have become aware of the Force Majeure condition or event, but in any event no later than thirty (30) Days after the Force Majeure condition or event begins, written notice (the "**Force Majeure Notice**") stating that the non-performing Party considers such condition or event to constitute Force Majeure and describing the particulars of such Force Majeure condition or event, including the date the Force Majeure commenced;

(b) the non-performing Party gives the other Party, within fourteen (14) Days Force Majeure Notice was or should have been provided, a written explanation of the Force Majeure condition or event and its effect on the non-performing Party's performance, which explanation shall include evidence reasonably sufficient to establish that the occurrence constitutes Force

Majeure;

(c) the suspension of performance is of no greater scope and of no longer duration than is required by the Force Majeure;

(d) the non-performing Party exercises commercially reasonable efforts to remedy its inability to perform and provides written weekly progress reports to the other Party describing actions taken to end the Force Majeure; and

(e) when the condition or event of Force Majeure ends and the non-performing Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party written notice to that effect.

ATTACHMENT B

FACILITY OWNED BY SELLER

1. The Facility.

(a) Drawings, Diagrams, Lists, Settings and As-Builts.

(i) Single-Line Drawing, Interface Block Diagram, Relay List, Relay Settings and Trip Scheme. A preliminary single-line drawing (including notes), Interface Block Diagram, relay list, relay settings, and trip scheme of the Facility shall, after Seller has obtained prior written consent from Company, be attached to this Agreement on the PUC Approval Date as **Attachment E** (Single-Line Drawing and Interface Block Diagram) and **Attachment F** (Relay List and Trip Scheme). A final single-line drawing (including notes), Interface Block Diagram, relay list and trip scheme of the Facility shall, after having obtained prior written consent from Company, be labeled the "Final" Single-Line Drawing, the "Final" Interface Block Diagram and the "Final" Relay List and Trip Scheme and shall supersede

Attachment E (Single-Line Drawing and Interface Block Diagram) and **Attachment F** (Relay List and Trip Scheme) to this Agreement and shall be made a part hereof on the Commercial Operations Date. After the Commercial Operations Date, no changes shall be made to the "Final" Single-Line Drawing, the "Final" Interface Block Diagram and the "Final" Relay List and Trip Scheme without the prior written consent of Seller and Company. The single-line drawing shall expressly identify the Point of Interconnection of Facility to Company System.

(g) Active Power Control Interface.

(i) Seller shall provide and maintain in good working order all equipment, computers and software associated with the control system (the "**Active Power Control Interface**") necessary to interface the Facility active power controls with the Company System Operations Control Center for real power control of the Facility by the Company System Operator.

The detailed design will be tailored to the specific resource type and configuration to achieve the functional requirements of the Facility.

The Active Power Control Interface will be used to control the net real power export (or import, as applicable) from the Facility for load following, system balancing, energy arbitrage, and/or supplemental frequency control as required under this **Attachment B** (Facility Owned by Seller).

For facilities with grid charging storage, the Active Power Control interface may also direct the charging/discharging of energy from the BESS.

The Facility real power output (or import, if storage charging is enabled) will automatically adjust to a change in frequency in accordance with the frequency response requirements provided in this **Attachment B** (Facility Owned by Seller).

(ii) Company shall review and provide prior written approval of the design for the Active Power Control Interface to ensure compatibility with Company's centralized control systems and use of Facility available energy and storage capabilities. To ensure such continued compatibility, Seller shall not materially change the approved design without Company's prior review and written approval. This will include design description and parameters for the Seller's control system(s), which determine provision of net real power the BESS storage, and charging of the BESS storage, in response to the Active Power Control signal or signals.

(iii) The Active Power Control Interface shall include, but not be limited to, a demarcation cabinet, ancillary equipment and software necessary for Seller to connect to Company's Telemetry and Control, located in Company's portion of the Facility switching station which shall provide the control signals to the Facility and send feedback status to the Company System Operations Control Center. The control type shall be analog output (set point) or raise/lower controls and will be established by the Company prior to final design approval.

(iv) The Active Power Control Interface shall also include provision for feedback points from the Facility indicating active power target in MW for the Active Power Control signal(s). The Facility shall provide the MW target feedback to the Company SCADA system immediately upon receiving the respective control signal from the Company.

(v) Seller shall provide to the telemetry interface analogs for the gross production of the energy resource(s) at the Facility (for example, DC or AC MW production of the Variable Resource generator(s), depending on design; gross DC MW of the BESS, etc.) Seller shall also provide the total net AC MW production at the Point of Interconnection.

(vi) The Active Power Control Interface shall provide for remote control of the real-power output of the Facility by the Company at all times. If the Active Power Control

Interface is unavailable or disabled, the Facility may not export electric energy to Company and the Facility shall be deemed to be in Seller-Attributable Unavailability status, unless the Company, in its sole discretion, agrees on an alternate means of dispatch. If Seller fails to provide such remote control capability (whether temporarily or throughout the Term), then, notwithstanding any other provision of this **Attachment B** (Facility Owned by Seller), Company shall have the right to derate or disconnect the entire Facility during those periods that such control capability is not provided and the Facility shall be deemed to be in Seller-Attributable Unavailability status for such periods.

(vii) The rate at which the Facility changes net real power in response to the active power control shall not be less than the greater of 2 MW per minute or 10% of the Facility capacity per minute, and shall make available through agreed parameters, such faster ramp as the installed equipment can support. The Facility's Active Power Control Interface will be used by Company to control the rate at which electric energy is changed to achieve the active power limit for load-following and regulation. The Facility will respond to the active power control request immediately with an echo of the set point and measurable change within the 4 second control cycle.

(viii) The Facility shall accept the following controls related to active power and frequency response to or from the Company centralized control system:

- Power Reference Setpoint from Company (based on the input to the Facility, from the Active Power Control Interface): The Facility output shall match this setting from the BESS so long as it can be supported by the variable resource and/or BESS State of Charge (Power Possible does not change). This net output should be accurate within +/- 0.1 MW under normal frequency conditions. This setpoint will be modified as appropriate in the controls by the appropriate frequency response consistent with **Section 1(g)(xi)** (Active Power – Frequency Response (DROOP)), **Section 1(g)(xii)** (Dynamic Active Power – Frequency Performance), and **Section 1(g)(xiii)** (Alternate Active Power / Frequency Response Modes) of this **Attachment B** (Facility Owned by Seller).

- For variable energy resources: The Facility shall include Variable Resource Enable/Disable control. When "Disable" is selected, the Facility shall ramp down, shutdown, and leave offline variable resource generators. When "Enable" is selected, the Facility variable resource generators can start up, ramp up, and remain in normal operations subject to Company active power dispatch.

- From Company: Frequency Response Mode (DROOP, FFR, isochronous) state (where alternate modes of operation are required).

- From Seller:

    - [For Facilities with a BESS and where required]: Capacity allocation to each mode of operation where ability to allocate capacity to different modes of operation is required (e.g., to allocate a portion of capacity to fast frequency response) and telemetered data and controls necessary to determine state of charge, and gross MW and Mvar contribution, etc. operationally required for each segmented use.

    - Power Possible (Available maximum capacity): See above, instantaneous limit for available energy, represents max level the Facility can produce under present resource, BESS State of Charge (if applicable) and equipment conditions. This is used as upper limit for Company Dispatch.

    - For Variable Energy Resources: max level the variable generation resources can produce under present variable resource and equipment conditions.

- Minimum Sustained Limit: Minimum output level the Facility can be reduced to continuously without delay (ecomn). For projects with BESS: If BESS charging from the grid is permitted, and charging capacity is available, this will be a negative value.
- Minimum Transient Limit (for frequency response, regulation) (lfcmn). For projects with BESS: If BESS charging from the grid is permitted, and charging capacity is available, this will be a negative value.
- Maximum Dispatchable Ramp Rate: Controlled ramp rate available for controlled changes in output.
- For projects with a BESS, Seller shall also provide the following:
  - BESS potential (BESS State of Charge and projected number of hours at present dispatch, minimum dispatch, and maximum dispatch).
  - Frequency Response Mode (DROOP, FFR, isochronous) state (where alternate modes of operation are required).
  - Capacity allocation to each mode of operation (to allow FFR and Droop allocation).

(ix) Seller shall not override Company's active power controls without first obtaining specific approval to do so from the Company System Operator unless there is a system emergency. Disabling of the remote Active Power Control shall initiate telemetry notification to the Company.

(x) The requirements of the Active Power Control Interface may be modified as mutually agreed upon in writing by the Parties.

Active Power Communications between Company and Seller

Company will receive and send AGC Set-Point and related data through the communications interface in accordance with Company standards. The data points covered under this Agreement, as described below, may overlap with data requirements described elsewhere.

AGC Data Points to be sent from Seller to Company via SCADA

The following data points will be transmitted via SCADA from Seller to Company and represent Facility level data

Description	Units
AGC Set-Point (echo)	MW
Power demand	MW
Actual power	MW
Power Possible	MW
Actual reactive power	Mvars
Average Voltage	Kv
Variable Generation potential	MW

[Wind only] Number of turbines online and running	Integer
BESS State of Charge	Pct
[PV only] Inverters online	Integer
Facility duration at current output	HRS
AGC Status	Remote/Local
[For facilities with alternate modes of frequency response] Indication of Frequency Response Mode	Integer FFR, Droop, ISOCH

Response times and limitations of Facility in regards to Active Power Control

The following protocols outline the expectations for responding to the AGC Set-Point.

Frequency of Changes. Company may send a new AGC Set-Point to the Facility at up to the AGC control cycle (present 4 seconds).

Range of AGC Set-Point. The range of set point values can be between 0% and 100% of Power Possible. For projects offering grid-charging storage, negative set-point values may be required.

Backup Communications

In the event of an AGC failure, Company and Seller shall communicate via telephone, or other method mutually agreeable between the Parties, in order to correct the failure

(xi) Active Power - Frequency Response (DROOP). The Facility shall provide a primary frequency response with a frequency droop characteristic reacting to system frequency at the Point of Interconnection in both the overfrequency and underfrequency directions except as limited by the minimum and maximum available capacity and energy potential at the time of the event including BESS state of charge. This response must be timely and sustained rather than injected for a short period and then withdrawn. For over-frequency events, response may include absorption through charging (as applicable under the terms of this Agreement). Seller shall provide minimum operational limits for each online resource and the Facility for primary frequency response.

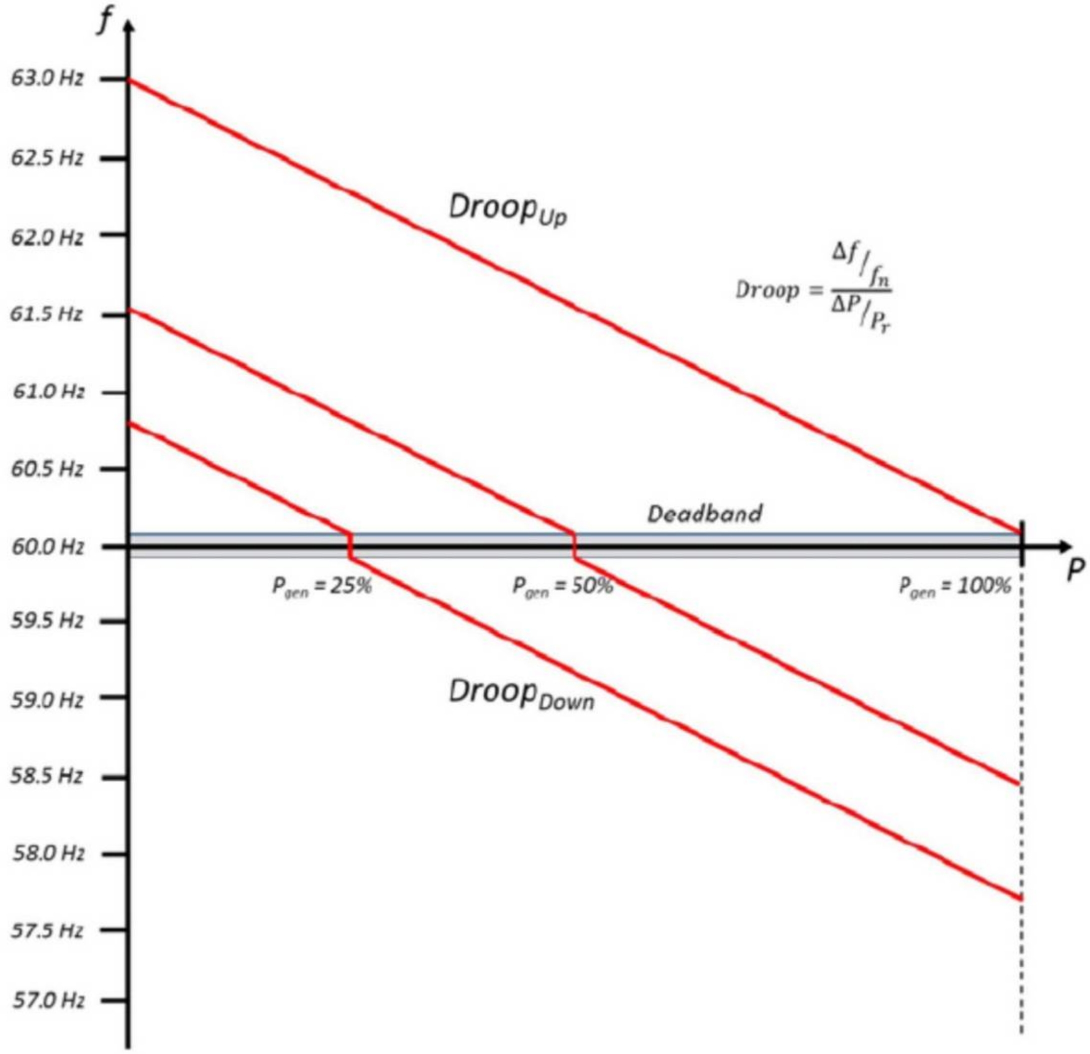
Frequency will be calculated over a period of time (e.g., three to six cycles, or other period as specified by Company), and filtered to take control action on the fundamental frequency component of the calculated signal. Calculated frequency may not be susceptible to spikes caused by phase jumps on the Company system.

The active power-frequency control system, and overall response of the inverter-based resource (plant), must meet the following performance aspects (see figure below):

The active power-frequency control system shall have an adjustable proportional droop characteristic with a default value of [4%] percent. The droop setting shall permit a setting from 0.1% to 10%. This setting shall be changed upon Company's written request as necessary for grid droop response coordination. The droop setting shall be tunable and may be specified during commissioning. The droop shall be a permanent value based on Pmax (maximum nominal active power output of the plant) and Pmin (typically 0 for an inverter based resource). This keeps the proportional droop constant across the full range of operation. The curve for an inverter-based BESS may include the negative active power quadrant of this curve. The droop response must include the capability to respond in both the upward (underfrequency) and downward (overfrequency) directions. Frequency droop will be based on the difference between maximum nameplate active power output (Pmax) and zero output (Pmin) such that the [4%] percent droop line is always constant for a resource.

Seller shall make commercially reasonable efforts to provide frequency response without a deadband, but in any case, not to exceed +/- 0.0166 Hz. If the active power-frequency control system has a deadband, it shall be a nonstep deadband that is adjustable between 0 Hz and the full frequency range of the droop characteristic with a default value not to exceed ± 0.036 Hz. (Nonstep deadband is where the change in active power output starts from zero deviation on either side of the deadband.) (Frequency deadband is the range of frequencies in which the unit does not change active power output.)

Inverter-based resources may consider a small hysteresis characteristic where linear droop meets any deadband to reduce dithering of inverter output when operating near the edges of the deadband. The hysteresis range may not exceed ± 0.005 Hz on either side of the deadband. If measurement resolution is not sufficient to measure this frequency, hysteresis may not be used.



Active Power - Frequency Control Characteristic

Nominal System Frequency is 60.00 Hz.

The closed-loop dynamic response of the active power-frequency control system of the overall inverter-based resources, as measured at the POI must have the capability to meet or exceed the performance specified in below. Seller shall ensure that the models and parameters for the resources and control equipment are consistent with those provided during the IRS process and that any updates have been provided to the Company reflecting currently implemented settings and configuration.

(xii) Dynamic Active Power-Frequency Performance. For a step change in frequency at the point of measure of the inverter-based resource[24]

Reaction time: The time between a step change in frequency and the time when the resource active power output begins responding to the change shall be less than 500 Ms, or as otherwise specified by Company.[25]

Rise time: The time when the resource has reached 90% of the new steady-state (target) active power output shall be less than 4 seconds, or as otherwise specified by Company.[26]

Settling Time: Time in which the resource has entered into, and remains within, the settling band of the new steady-state active power (target) output shall be less than 10 seconds, or as otherwise specified by Company.

Overshoot: Percentage of the rated active power output that the resource can exceed while reaching the settling band shall be less than 5% or as otherwise specified by Company.[27]

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[24] Item may be adjusted based on the Interconnection Requirements Study ("IRS")
[25] Time between step change in frequency and the time to 10 percent of new steady-state value can be used as a proxy for determining this time.
[26] Percentage based on final (expected) settling value.
[27] Percentage based on final (expected) settling value.

Settling Band: Percentage of rated active power output that the resource should settle to within the settling time shall be less than 2.5%.

When operating in parallel with the Company System, the Facility shall operate with its primary frequency response control in automatic operation and in accordance with Company directions. Notification of changes in the status of the frequency response controls and, where applicable, mode of operation must be provided to the Company System Operator immediately through SCADA telemetry indication.

The Facility frequency response control shall adjust, without intentional delay and without regard to the ramp rate limits in **Section 3(c)** (Ramp Rates) of this **Attachment B** (Facility Owned by Seller), the Facility's net real power export based on frequency deadband and frequency droop settings specified by the Company.

The Facility frequency response control shall increase the net real power export above the Power Reference Setpoint set under **Section 1(g)(viii)** of this **Attachment B** (Facility Owned by Seller) or further decrease the net real power export from the Power Reference Limit in its operations in accordance with the frequency response settings.

The Facility frequency response control shall be in continuous operation unless directed otherwise by the Company.

(xiii) Alternate Active Power/ Frequency Response Modes. The Facility will provide the capability to supply isochronous or fast frequency response modes of operation, in addition to normal droop, which can be set remotely or locally. The control design shall allow for a bumpless transfer between modes of operation.

A. Fast Frequency Response (FFR): This mode of operation will permit the Facility to respond to system frequency disturbances with a fast charge/discharge response in accordance with the fast frequency response droop settings. In this mode of operation, the Facility frequency response is configured to provide fast frequency response, as an alternative setting to the normal steady-state frequency response. When in this mode of operation, the frequency droop characteristics are configured to charge or discharge with a different set of parameters to allow for a faster and larger proportional charge and discharge in response to frequency changes outside of the configurable deadband. The initial parameter settings will be specified by Company following the IRS and additional tuning and adjustment of configurable parameters may be required based on review of response to actual system events. When in FFR mode, when system frequency is within the fast frequency response deadband, the Facility will operate to maintain a percentage state of charge, which is configurable on Company request (i.e., 50%) managed at a charging/discharging rate, also specified by Company.

(1) When in FFR mode the active power-frequency control system shall have an adjustable FFR proportional droop characteristic with a default value of [1%] percent. The FFR droop setting shall permit a setting from 0.1% to 5%. This setting shall be changed upon Company's written request as necessary for fast frequency response coordination. The FFR droop shall be a permanent value based on Pmax (maximum nominal active power output of the plant) and Pmin (typically 0 for an inverter-based resource). This keeps the proportional droop constant across the full range of operation. The curve for an inverter-based BESS may include the negative active power quadrant of this curve. The droop response must include the capability to respond in both the upward (underfrequency) and downward (overfrequency) directions. Frequency droop will be based on the difference between maximum nameplate active power output (Pmax) and zero output (Pmin) such that the [1%] percent droop line is always constant for a resource.

(2) When in FFR mode the active power-frequency control system shall have an adjustable frequency deadband with a default value of 0.3 Hz. The deadband setting shall permit a setting from 0.1 Hz to 1 Hz. This setting shall be changed upon Company's written request as necessary for fast frequency response coordination. The deadband setting shall be tunable and may be specified during commissioning. It shall be a nonstep deadband such that the change in active power output starts from zero deviation on either side of the deadband. (Frequency deadband is the range of frequencies in which the unit does not change active power output.)

(3) FFR-1 Performance Requirements – Expected FFR Active Power-Frequency Performance. For a step change in frequency at the point of measure of the FFR resource:

Reaction time: The time between a step change in frequency and the time when the resource active power output begins responding to the change shall be less than 50 milliseconds, or as otherwise specified by Company.[28]

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[28] Time between step change in frequency and the time to 10 percent of new steady-state value can be used as a proxy for determining this time.

Rise time: The time when the resource has reached 90% of the new steady-state (target) active power output shall be less than 0.133 seconds, or as otherwise specified by Company.[29]

Settling Time: Time in which the resource has entered into, and remains within, the settling band of the new steady-state active power (target) output shall be less than 500 milliseconds, or as otherwise specified by Company.

Overshoot: Percentage of the rated active power output that the resource can exceed while reaching the settling band shall be less than 5% or as otherwise specified by Company.[30]

Settling Band: Percentage of rated active power output that the resource should settle to within the settling time shall be less than 2.5%.

B. Isochronous / Black Start: The Facility will be capable of operating in a zero droop (isochronous) mode of operation. When in this mode of operation, the frequency droop characteristic will be configured as needed to keep system frequency at a target. In a black start configuration, the target shall be 60 Hz. If isochronous is specified while in operation, the target shall be initialized to the grid frequency and the target increased or decreased from the Company System through the control interface.

[29] Percentage based on final (expected) settling value.
[30] Percentage based on final (expected) settling value.

1j. Demonstration of Facility. Company shall have the right at any time, other than during maintenance or other special conditions communicated by Seller, to notify Seller in writing of Seller's failure, as observed by Company and set forth in such written notice, to meet the operational and performance requirements specified in **Section 4.6** (Fast Frequency Response Performance Metric) of this Agreement, and **Section 1(b)(iii)(I)**, **Section 1(g)** (Active Power Control Interface) and **Section 3** (Performance Standards) of this **Attachment B** (Facility Owned by Seller), and to require documentation or testing to verify compliance with such requirements. Upon receipt of such notice, Seller shall promptly investigate the matter, implement corrective action and provide to Company, within thirty (30) Days of such notice, a written report of both the results of such investigation and the corrective action taken by Seller; provided, that, if thirty (30) Days is not a reasonable time period to investigate the matter, implement corrective action and provide such written report, Seller shall complete the foregoing within such longer commercially reasonable period of time agreed to by the Parties in writing. If the Seller's report does not resolve the issue to Company's reasonable satisfaction, the Parties shall promptly commission a study to be performed by one of the engineering firms then included on the Qualified Independent Third-Party Consultants List attached to the Agreement as **Attachment D** (Consultants List) to evaluate the cause of the non-compliance and to make recommendations to remedy such non-compliance. Seller shall pay for the cost of the study. The study shall be completed within ninety (90) Days, unless the selected consultant determines such study cannot reasonably be completed within ninety (90) Days, in which case, such longer period of time as the selected consultant determines is necessary to complete such study shall apply. The consultant shall send the study to Company and Seller. Seller (and/or its third-party consultants and contractors), at Seller's expense, shall take such action as the study shall recommend with the objective of resolving the non-compliance. Such recommendations shall be implemented by Seller to Company's reasonable satisfaction no later than forty-five (45) Days from the Day the completed study is issued by the consultant, unless such recommendations cannot reasonably be implemented within forty-five (45) Days, in which case, Seller shall implement such recommendations within such longer commercially reasonable period of time agreed to by the Parties in writing. Failure to implement such recommendations within this period shall constitute a material breach of this Agreement. Unless the aforementioned written report and study are being completed, and any recommendations are being implemented, solely to address Seller's failure to satisfy the requirements of **Section 3(w)** (Round Trip Efficiency) of this **Attachment B** (Facility Owned by Seller), Company shall have the right to declare the Facility derated and in Seller-Attributable Unavailability status until the Seller's aforementioned written report has been completed, any subsequent study commissioned by the Parties has been completed and any recommendations to resolve the non-compliance have been implemented to Company's reasonable satisfaction.

3. Performance Standards.

(a) Reactive Power Control. Seller shall control its reactive power by automatic voltage regulation control. Seller shall automatically regulate voltage at a point, the point of regulation, between the Seller's generator terminal and the Point of Interconnection to be specified by Company, to within 0.5% of a voltage or power factor specified by the Company System Operator to the extent allowed by the Facility reactive power capabilities as defined in **Section 3(b)** (Reactive Power Characteristics) of this **Attachment B** (Facility Owned by Seller)

(b) Reactive Power Characteristics.

(i) The Facility must deliver power up to the Allowed Capacity (MW) at a power factor between 95% lagging and 95% leading to the Company System as illustrated in the generator capability curve(s) attached to this Agreement as **Exhibit B-2**, which represents the Facility Composite (Generator and Energy Storage Capability Curve(s)). Facilities with a BESS with grid charging can operate with negative active power. These facilities shall provide automatic voltage control within their reactive capability while acting as a load (charging, negative active power generation). The automatic voltage control aspects of a BESS shall be seamless across the transition from acting as a generating resource to acting as a load. The Facility must be capable of automatically adjusting reactive control to maintain the bus voltage at the Point of Interconnection to meet the scheduled voltage set point target specified by the Company System Operator and be capable of supplying reactive power at the leading/lagging 0.95 power factor at all active power outputs down to zero active power. The voltage target will be specified remotely by the Company System Operator through the SCADA/EMS. The Facility's voltage set point target must reflect the Company voltage set point target controlled from the SCADA/EMS, without delay. The Facility should not normally operate on a fixed var or fixed power factor unless agreed by Company. The voltage setpoint target and present Facility minimum and maximum reactive power limits based on the Facility Composite capability curve shall be provided to the Company EMS through Company's Telemetry and Control.

(ii) The Facility shall contain equipment able to continuously and actively control the output of reactive power under automatic voltage regulation control reacting to system voltage changes. The response requirements are differentiated for large and small signal disturbance performance characteristics. Small signal disturbances are those that reflect normal variations under non-disturbance conditions, the continuous operation range for voltage ride through: 0.80 pu ≤ V ≤ 1.00 pu at the point of interconnection. Large disturbance is where the voltage at the point of interconnection falls outside the continuous operating range.

(iii) For small signal disturbances, reaction time between the step change in voltage and the reactive power change shall be less than 500 msec (no intentional time delay). The automatic voltage regulation response speed at the point of regulation shall be such that at least 90% of the initial voltage correction needed to reach the voltage control target will be achieved within 1 second following a step change. The percentage of rated reactive power output that the resource can exceed while reaching the settling band shall be less than five percent (5%).

(iv) Large disturbances: Large disturbances are characterized by voltage falling outside of the continuous operating range. The Facility shall adhere to the following characteristics for large disturbances:

> The response of each generating resource over its full operating range and for all expected grid conditions should be stable. The dynamic performance of each resource should be tuned to provide this stable response. Company will work with Seller to ensure during the interconnection process that each resource supports Company System reliability and provides a stable transient response to grid events.
>
> Inverter-based resources shall operate in closed loop automatic voltage control at all times to support voltage regulation and voltage stability. Either the individual inverters or the plant-level closed loop automatic voltage controller must operate with a relatively fast response characteristic to mitigate steady-state voltage issues

from causing dynamic voltage collapse. The plant-level controller may send voltage or reactive power set point changes to the individual inverters relatively fast, or the inverters will respond locally (depending on control architecture).

For a large disturbance step in voltage, measured at the inverter terminals, where voltage falls outside the continuous operating range, the positive sequence component of the inverter reactive current response must meet the performance specifications set forth below. These parameters may be adjusted following additional study and/or operational testing and performance.

Reaction time: Time between the step change in voltage and when the resource reactive power output begins responding to the change. The reaction time shall be less than 16 msec.

Rise time: Time between a step change in control signal input and when the reactive power output changes by 90 percent of its final value. The rise time shall be less than 100 msec.

Overshoot: Percentage of rated reactive current output that the resource can exceed when reaching the settling band. Overshoot will be determined following the IRS such that any overshoot in reactive power response does not cause Company System voltages to exceed acceptable voltage limits. The magnitude of the dynamic response may be requested to be reduced based on stability studies or actual operational data review.

(v) If the Facility does not operate in accordance with **Section 3(b)** (Reactive Power Characteristics) of this **Attachment B** (Facility Owned by Seller), Company may disconnect all or a part of Facility from Company System until Seller corrects its operation (such as by installing supplemental reactive power equipment or additional controls modifications, at Seller's expense).

(c) **Ramp Rates.** Seller shall ensure that the ramp rate of the Facility is less 2 MW a minute for all conditions other than those under control of the Company System Operator and/or those due to desired frequency response, including start up, depletion of storage charge and resource, locally controlled startup and shut down.

(d) **Ride-Through.** Ride-Through requires that the resource continues to inject current within the "No Trip" zone of the voltage and frequency ride-through requirements. Unless approved during the Interconnection Requirements Study analysis, resources should not use "momentary cessation" within the ride-through regions for any of the ride-through requirements in this **Attachment B** (Facility Owned by Seller).

(e) **Undervoltage Ride-Through.** The Facility, as a whole, will meet the following undervoltage ride-through requirements during low voltage affecting one or more of the three voltage phases ("V" is the voltage of any three voltage phases at the Point of Interconnection). For alarm conditions the Facility shall not disconnect from the Company System unless the Facility's equipment is at risk of damage. This is necessary in order to coordinate with the existing Company System.

$0.80 \text{ pu} \leq V \leq 1.00 \text{ pu}$	The Facility remains connected to the Company System and in continuous operation.
$0.00 \text{ pu} \leq V < 0.80 \text{ pu}$	The Facility remains connected to the Company System

and in continuous operation for a minimum of 600 milliseconds per event (while "V" remains in this range). The Facility may initiate an alarm if "V" remains in this range for more than 600 milliseconds; the duration of the event is measured from the point at which the voltage drops below 0.80 pu and ends when the voltage is at or above 0.80 pu. The 600 milliseconds represents a delayed clearing time of 30 cycles plus breaker opening time.

Protective Undervoltage Relaying (27) shall be set to alarm only to meet the above ride-through requirements, and shall not initiate a disconnect from the Company System unless Seller reasonably determines based upon Good Engineering and Operating Practices that the Facility's equipment is at risk of damage. This is necessary in order to coordinate with the existing Company System.

Seller shall have sufficient capacity to fulfill the above mentioned requirements to ride-through subsequent events 300 cycles or more apart, between which the voltage at the POI recovers above 0.80 pu.

(f) Over Voltage Ride-Through. The overvoltage protection equipment at the Facility shall be set so that the Facility will meet the following overvoltage ride-through requirements during high voltage affecting one or more of the three voltage phases (as described below) ("V" is the voltage of any of the three voltage phases at the Point of Interconnection). For alarm conditions the Facility should not disconnect from the Company System unless the Facility's equipment is at risk of damage. This is necessary in order to coordinate with the existing Company System

$1.00 \text{ pu} < V \leq 1.10 \text{ pu}$	The Facility remains connected to the Company System.
$1.10 \text{ pu} < V \leq 1.15 \text{ pu}$	The Facility remains connected to the Company System and in continuous operation no less than 30 seconds; the duration of the event is measured from the point at which the voltage increases at or above 1.1 pu and ends when voltage is at or below 1.1 pu.
$V > 1.15 \text{ pu}$	The Facility remains connected to the Company System and in continuous operation for as long as possible as allowed by the equipment operational limitations.

Protective Overvoltage Relaying (59) shall be set to alarm only to meet the above ride-through requirements, and shall not initiate a disconnect from the Company System unless Seller reasonably determines based upon Good Engineering and Operating Practices that the Facility's equipment is at risk of damage. This is necessary in order to coordinate with the existing Company System.

(g) Transient Stability Ride-Through. The Facility shall be designed such that the transient stability of Company System is maintained for normally cleared and secondarily cleared faults. The Facility will be required to remain connected through anticipated rates of change of frequency

(h) Reserved.

(i) Underfrequency Ride-Through. The Facility shall meet the following underfrequency ride-through requirements during an underfrequency disturbance, and export of power shall continue with output adjusted as appropriate for Facility droop response consistent with **Section 1(g)(xi)** (Active Power – Frequency Response (DROOP)), **Section 1(g)(xii)** (Dynamic Active Power – Frequency Performance), and **Section 1(g)(xiii)** (Alternate Active Power / Frequency Response Modes) of this **Attachment B** (Facility Owned by Seller) ("f" is the Company System frequency at the Point of Interconnection):

$57.0\,\text{Hz} \leq f \leq 60.0\,\text{Hz}$	The Facility remains connected to the Company System and in continuous operation.
$56.0\,\text{Hz} \leq f \leq 57.0\,\text{Hz}$	The Facility remains connected to the Company System and in continuous operation for at least six (6) seconds per event. The duration of the event is from the point at which the frequency is below 57 Hz and ends when the frequency is at or above 57 Hz. The Facility may initiate an alarm if frequency remains in this range for more than six (6) seconds.
$f < 56.0\,\text{Hz}$	The Facility remains connected to the Company System and in continuous operation for the duration allowed by the equipment operational limitations. The Facility may initiate an alarm immediately.

Protective Underfrequency Relaying (81U) shall be set to alarm only to meet the above ride-through requirements, and shall not initiate a disconnect from the Company System unless Seller reasonably determines based upon Good Engineering and Operating Practices that the Facility's equipment is at risk of damage. This is necessary in order to coordinate with the existing Company System.

Any tripping on calculated frequency should be based on accurately calculated and filtered frequency measurement over a time frame of minimum six cycles, or other period as specified by the Company, and should not use an instantaneously calculated value.

(j) Overfrequency Ride-Through. The Facility will behave as specified below for overfrequency conditions, and export of power shall continue with output adjusted as appropriate for Facility droop response consistent with **Section 1(g)(xi)** (Active Power – Frequency Response (DROOP)), **Section 1(g)(xii)** (Dynamic Active Power – Frequency Performance), and **Section 1(g)(xiii)** (Alternate Active Power / Frequency Response Modes) ("f" is the Company System frequency at the Point of Interconnection):

60.0 Hz $\leq$ f $\leq$ 61.5 Hz	The Facility remains connected to the Company System and in continuous operation.
61.5 Hz < f $\leq$ 63.0 Hz	The Facility remains connected to the Company System for at least ten (10) seconds. After ten seconds the Facility may initiate an alarm and the Facility remains connected and producing power for the duration allowed by the equipment operational limitations. The duration of condition is from the point at which the frequency is above 61.5 Hz and ends when the frequency is at or below 63.0 Hz.
f > 63.0 Hz	The Facility remains connected to the Company System for the duration allowed by the equipment operational limitations. The Facility may initiate an alarm immediately.

Protective Overfrequency Relaying (81O) shall be set to alarm only to meet the above ride-through requirements, and shall not initiate a disconnect from the Company System unless

Seller reasonably determines based upon Good Engineering and Operating Practices that the Facility's equipment is at risk of damage. This is necessary in order to coordinate with the existing Company System.

Any tripping on calculated frequency should be based on accurately calculated and filtered frequency measurement over a time frame of minimum six cycles, or other period as specified by the Company, and should not use an instantaneously calculated value.

(k) Successive Faults. If the resource necessitates tripping to protect from the cumulative effects of those successive faults, in a period of time to ensure safety and equipment integrity, the constraint and time periods should be provided for inclusion in the interconnection study. For all cases, at a minimum, the ride-through requirements shall be met for two ride-through events within two seconds to allow for the Company's transmission automatic reclosing attempt[24].

(l) Rate of Change of Frequency ("ROCOF"). The inverter-based resources in the Facility shall not use rate-of-change-of-frequency protection unless an equipment limitation exists that requires the inverter to trip on high ROCOF. Any ROCOF tripping must be approved by Company.

(m) Phase Angle Shift Ride-Through. The Facility equipment shall ride through phase angle shift of up to ([ ]) **[Note – requirements will depend on Facility].** Inverter phase lock loop (PLL) loss of synchronism shall not cause the inverter to trip or enter momentary cessation within the voltage and frequency ride-through region. Inverters must be capable of riding through temporary loss of synchronism, and regain synchronism, without causing a trip or momentary cessation of the resource.

(n) DC Protection. If the Facility requires DC reverse current protection, such protection must be coordinated with the inverter equipment module ratings and set to operate for short circuits on the DC side. DC reverse current protection shall not operate for transient overvoltage or for AC-side faults.

(o) Voltage Flicker. Any voltage flicker on the Company System caused by the Facility shall not exceed the limits stated in IEEE Standard 1453-2011, or latest version "Recommended Practice – Adoption of IEC 61000-4-15:2010, Electromagnetic compatibility (EMC) – Testing and measurement techniques – Flickermeter – Functional and design specifications."

(p) Harmonics. Harmonic distortion at the Point of Interconnection caused by the Facility shall not exceed the limits stated in IEEE Standard 519-1992, or latest version "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems." Seller shall be responsible for the installation of any necessary controls or hardware to limit the voltage and current harmonics generated from the Facility to defined levels.

(q) Grid Forming Capabilities. Seller Facility inverters shall be capable of operating in grid forming mode supporting system operation under normal and emergency conditions without relying on the characteristics of synchronous machines. This includes operation as a current independent ac voltage source during normal and transient conditions (as long as no limits are reached within the inverter) and the ability to synchronize to other voltage sources or operate autonomously if a grid reference is unavailable.

(i) Seller shall operate the Facility in grid forming mode only as directed by the Company System Operator, in its sole discretion. Such mode of operation shall be indicated to the Company System Operator through telemetry.

(ii) The Facility shall include safeguards to prevent the unintentional switching of the Facility into and out of grid forming mode. The safeguards shall be approved in writing by the Company and implemented by the Seller prior to control system testing.

(r) Black Start Capability. The BESS storage shall be capable of grid forming inverter capability so it can generate its own AC waveform rather than relying on a grid voltage to synchronize and maintain frequency. Further, inverter-based resources shall ensure they have sufficient energy storage to maintain power injection to the grid during system restoration (i.e., have power available when and if called upon). Inverter based facilities should be capable of support as a black start cranking path to start synchronous generators for restoration.

(s) Provision of Synthetic Inertia.

(t) Generator Step-Up Transformer Impedance. The generator step-up transformer impedance shall be between [ ] percent and [ ] percent, inclusive, on transformer OA rating[24].

(u) Control Systems and Auxiliary Equipment. The power source for control systems and auxiliary equipment required for normal operation of the Facility shall be designed to be immune from system transients in accordance with the Public Utilities Commission of the State of Hawaii tariff for Hawaii Electric Light Company, Inc. Rule No. 2, Character of Service (Revised Sheet No. 5, effective Oct. 20, 1991) and Section 3.2(A)(6) (Facility Protection and Control Equipment) to meet the performance during under/over voltage and under/over frequency conditions pursuant to **Section 3(e)** (Undervoltage Ride-Through), **Section 3(f)** (Over Voltage Ride-Through), **Section 3(i)** (Underfrequency Ride-Through) and **Section 3(j)** (Overfrequency Ride-Through) of this **Attachment B** (Facility Owned by Seller).

(v) Frequency Response. Seller shall comply with the requirements of **Section 1(g)(xi)** (Frequency Response (DROOP)), **Section 1(g)(xii)** (Dynamic Active Power –

Frequency Performance), and **Section 1(g)(xiii)** (Alternate Active Power / Frequency Response Modes) of this **Attachment B** (Facility Owned by Seller).

(w) Round Trip Efficiency. The round trip efficiency of the BESS as measured at the Point of Interconnection shall be not less than 83 percent (83%).

8(v) Data Collection.

A. High Resolution Data: Seller shall install and make available to the Company time stamped and sequential data recordings for all inverter-based resources (and all generating resources) to perform event analysis and verify Facility performance during steady state and transient disturbance events. This will include a time-synchronized phasor measurement unit at the Facility, and access to multiple sources to provide sufficient clarity as to any abnormal response or behavior within the Facility, including Facility control settings and static values, SCADA data, sequence of events recording (SER) data, dynamic disturbance recorder (DDR) data, and inverter fault codes and inverter-level dynamic recordings. This data will be used to review the Facility's response to system dynamics, such as the frequency response (normal droop and FFR), reactive response, etc.

B. Plant Data: Seller shall install at least three (3) meteorological tower(s), spaced so as to provide the data points set forth below for the entire Facility. At least two months prior to the Commercial Operation Date, Seller shall deliver to Company a report showing (i) manufacturer, model and year of all energy equipment (inverters, energy storage devices), and meteorological instrumentation, and (ii) the latitude and longitude of the center of the energy equipment (i.e., solar panels for every inverter, wind turbines) and every meteorological tower. Beginning upon COD, Seller shall transmit and provide to Company the real-time data set forth below, refreshed as frequently as allowed by the SCADA system, not to exceed sixty (60) second intervals:

- Three (3) data points from each inverter:
  - Inverter generation (MW)
  - Inverter availability
  - Inverter on/offline status

Seller shall provide a map and key for each inverter sufficient to allow Company to correlate the data received through Company's data historian system to each individual resource.

ATTACHMENT G

COMPANY-OWNED INTERCONNECTION FACILITIES

1(f). Review of the Listing and Costs. If the Commercial Operations Date is not achieved by the Guaranteed Commercial Operations Date, as such date may be extended as provided in **11.4** (Milestone Dates), the listing of the Company-Owned Interconnection Facilities required in this Agreement and the cost-estimates for such Company-Owned Interconnection Facilities are subject to review and revision. Such revision may include, but not be limited to, such items as reconductoring an existing transmission or distribution line, construction of a new line, increase transformer capacity, and alternative relay specifications. In addition, such review and revision may require that the Company re-perform or update the IRS at Seller's expense.

2(f) Acceptance Test Procedures.

(i) Seller acknowledges that: (aa) Company has multiple on-going projects with other developers as well as its own capital improvement projects and on-going system work; (bb) Company has limited resources to provide engineering oversight (such as review of plans) to such projects and to participate in the testing of such projects; (cc) in order for Company to accommodate such oversight and testing, it is necessary for Company to sequentially allocate its resources for each project a year or more in advance; (dd) the result is a queue of such projects that reflects the scheduling commitments of Company's resources to conduct such oversight and to participate in such testing; (ee) if a project is behind the schedule on which Company's resources have been scheduled for the oversight of such project, or if a project is not ready for testing at the time Company's resources have been scheduled for the testing of such project, or if a project does not complete testing within the period for which Company's resources have been scheduled for such testing, the progress of projects later in the queue may be adversely affected; (ff) the Test Ready Deadline that is set forth in **Attachment K-1** (Seller's Conditions Precedent and Company Milestones) reflects the scheduling commitment of Company's resources to (i) conduct the oversight necessary to facilitate Seller's achievement of that Test Ready Deadline, (ii) commence the Acceptance Test on the Acceptance Testing Milestone Date that is set forth in **Attachment K-1** (Seller's Conditions Precedent and Company Milestones) and (iii) thereafter participate in the Control System Acceptance Test; and (gg) in the Company's sole discretion based on its assessment of Company's resources and overall schedule of projects at the time, the Project may lose its place in the queue and may be assigned a new Acceptance Testing Milestone Date for commencement of the Acceptance Test that may be behind the other projects then in the queue if (i) Seller fails to satisfy any of the conditions precedent set forth in **Section 2(f)(ii)** of this **Attachment G** (Company-Owned Interconnection Facilities) within the time period specified therein for the task in question or, if no time period is specified therein, by the Test Ready Deadline, (ii) the Seller fails to satisfy any of the Seller's Conditions Precedent set forth in **Attachment K-1** (Seller's Conditions Precedent and **Company**

Milestones) and/or (iii) the Acceptance Test and the Control System Acceptance Test are not satisfactorily completed within the time allotted to complete such testing.

(ii) The Conduct of the Acceptance Test is subject to the satisfaction of the following conditions precedent within the time period specified below for the task in question or, if no time period is specified, by the Test Ready Deadline that is set forth in **Attachment K-1** (Seller's Conditions Precedent and Company Milestones):

(A) Final Single-Line Drawing, and notes, has received Company's written consent pursuant to **Section 1(a)(i)** (Single-Line Drawing, Interface Block Diagram, Relay List, Relay Settings and Trip Scheme) of **Attachment B** (Facility Owned by Seller) to this Agreement.

(B) Final Relay List and Trip Scheme have received Company's written consent pursuant to **Section 1(a)(i)** (Single-Line Drawing, Interface Block Diagram, Relay List, Relay Settings and Trip Scheme) of **Attachment B** (Facility Owned by Seller) to this Agreement.

(C) Final Interface Block Diagram has received Company consent pursuant to **Section 1(a)(i)** (Single-Line Drawing, Interface Block Diagram, Relay List, Relay Settings and Trip Scheme) of **Attachment B** (Facility Owned by Seller) to this Agreement.

(D) Final Control System Telemetry and Control List has received Company consent.

(E) Final phasor measurement unit (PMU) devices, if applicable, have received Company consent.

(F) Control system design and tunable parameters reviewed and mutually agreed upon as needed to meet the Company requirements in accordance with **Section**

3 (Performance Standards) of **Attachment B** (Facility Owned by Seller) to this Agreement.

(G) Agreement on Active Power Control Interface.

(H) No later than fourteen (14) Days prior to commencement of the Acceptance Test:

(1) Seller shall have certified to Company that Seller-Owned Interconnection Facilities have been installed and commissioned and such certification has not, prior to the commencement of the Acceptance Test, been subsequently challenged by Company on the basis of onsite observations made by the Company's representatives following the walk-through to be conducted pursuant to **Section 2(f)(iii)** of this **Attachment G** (Company-Owned Interconnection Facilities).

(2) Seller shall have certified to Company that any Company-Owned Interconnection Facilities built by Seller (and/or its Contractors) have been installed and commissioned and such certification has not, prior to the commencement of the Acceptance Test, been subsequently challenged by Company on the basis of onsite observations made by the Company's representatives following the walk-through to be conducted pursuant to **Section 2(f)(iii)** of this **Attachment G** (Company-Owned Interconnection Facilities).

(I) Any Company-Owned Interconnection Facilities not built by or on behalf of Seller have been installed and commissioned.

(J) No later than seven (7) Days prior to the commencement of the Acceptance Test, Seller and Company shall have participated in walk-through of fully constructed Interconnection Facilities.

(K) Redlined as-built drawings of the Seller-Owned Interconnection Facilities and any of the Company-Owned Interconnection Facilities built by Seller (and/or its

Contractors) shall have been provided to Company.

(L) Continuous power is being supplied to Company's protection and SCADA equipment.

(M) Not less than four (4) weeks prior to the commencement of the Acceptance Test, the high speed communication lines required under this Agreement have been commissioned and are ready for use for EMS and revenue metering purposes.

(N) Not less than two (2) weeks prior to the commencement of the Acceptance Test, Seller and Company have participated in an on-Site Acceptance Test coordination meeting.

(iii) Seller shall provide Company with at least fourteen (14) Days advance written notice of the Acceptance Test, which shall be scheduled during normal business hours on a Business Day (and may take a minimum of thirty (30) Days to complete). No electric energy will be delivered from Seller to Company during this Acceptance Test. No later than thirty (30) Days prior to conducting the Acceptance Test, Company and Seller shall agree on a written protocol setting out the detailed procedure and criteria for passing the Acceptance Test. **Attachment N** (Acceptance Test General Criteria) provides general criteria to be included in the written protocol for the Acceptance Test. At the time that Seller provides its 14-Day notice of the Acceptance Test to Company, Seller shall concurrently schedule a site walk-through of the Facility with Company to occur no later than seven (7) Days prior to the Acceptance Test. Seller's 14-Day notice to Company of the Acceptance Test shall constitute its certification that (A) the installation and commissioning of the Seller-Owned Interconnection Facilities and the Company-Owned Interconnection Facilities built by Seller (and/or its Contractors) has been completed; and (B) a walk-through by Company shall demonstrate, to Company's reasonable satisfaction, Seller's readiness to commence with the Acceptance Test. If, after the site walk-through, Company representatives reasonably determine that Seller is not ready to commence with the Acceptance Test, the Project will lose its place in the queue and will be assigned a new Test Ready Deadline and a new Acceptance Testing Milestone Date. In the meantime, Seller shall remediate the deficiencies identified by Company, and the process described in this **Section 1(f)** (Acceptance Test Procedures) of **Attachment G** (Company-Owned Interconnection Facilities), shall commence again until Seller's readiness for the Acceptance Test is demonstrated to Company's reasonable satisfaction. Successful completion of the Acceptance Test requires successful completion of each of the individual tests that comprise the Acceptance Test. Retesting of any individual test constitutes as restart of the Acceptance Test if such retesting is required because of a prior failure of such individual test or because a prior test could not be completed because of a problem with the Facility. Within fifteen (15) Business Days of successful completion of the Acceptance Test and Company's receipt of the final report setting forth the results of the Acceptance Test, Company shall notify Seller in writing whether the Acceptance Test has been passed and, if so, the date upon which the Acceptance Test was passed.

ATTACHMENT K

GUARANTEED PROJECT MILESTONES

Guaranteed Project Milestone Date	**Description of Each Guaranteed Project Milestone**
N/A	Construction Financing Milestone: Seller shall provide Company with documentation reasonably satisfactory to Company evidencing (a) the closing on financing for the Facility including ability to draw on funds by **[insert same date certain as in left column]** or (b) the financial capability to construct the Facility**Error! Bookmark not defined.**
N/A	Permit Application Filing Milestone: Seller shall provide Company with documentation reasonably satisfactory to Company evidencing the filing by or on behalf of Seller of the following applications for Governmental Approvals required for the ownership, construction, operation and maintenance of the Facility:
9/30/2021	Administrative Permits Division, Hawai‘i County Planning Department * HCC 25-2-71(c)(1) Plan Approval Building Division of the County of Hawai‘i Department of Public Works * HCC §5-19, Building Permit
12/30/2022	Guaranteed Commercial Operations Date

ATTACHMENT K-1

SELLER'S CONDITIONS PRECEDENT AND COMPANY MILESTONES

Seller's Conditions Precedent Date	**Description of Each of Seller's Conditions Precedent**
N/A	Seller shall make payment to Company of the amount required under **Section 3(b)(ii)** of **Attachment G** (Company-Owned Interconnection Facilities)**Error! Bookmark not defined.**
N/A	Seller shall provide Company a right of entry for the Company-Owned Interconnection Facilities site(s).
N/A**Error! Bookmark not defined.**	Seller shall make payment to Company of the amount required under **Section 3(b)(iii)** of **Attachment G** (Company-Owned Interconnection Facilities)**Error! Bookmark not defined.**
10/29/2021	Seller's EPC Contractor shall obtain grading permit.
N/A	Seller's EPC Contractor shall obtain and provide Company all permits (other than any required occupancy permits, if applicable), licenses, easements and approvals to construct the Company-Owned Interconnection Facilities, including the building permit.
No later than three (3) months prior to commencement of the Acceptance Test	Seller shall provide station service power, if applicable, as required by Company.
No later than three (3) months prior to the commencement of the Acceptance Test	Seller or Seller's EPC Contractor shall have Hawaiian Telcom Backup (or equivalent) installed which shall consist of a 1.5 Mbps Routed Network Services circuit for backup SCADA communications from Company's Substation at Seller's Facility to Company's EMS located at the Company's control center.
8/31/2022	Seller's EPC Contractor shall complete installation of physical bus and structures within Company's substation up to the demark point as necessary to interconnect.

10/3/2022 ("Test Ready Deadline")	Seller's EPC Contractor shall complete construction of the Seller-Owned Interconnection Facilities, Seller shall have satisfied the conditions precedent to the conduct of the Acceptance Test set forth in **Section 2(f)(ii)** of **Attachment G** (Company-Owned Interconnection Facilities) and Seller is otherwise ready to conduct the Acceptance Test.
3/30/2022	Seller shall close grading permit, unless Seller provides documentation establishing, to Company's reasonable satisfaction, that closing the grading permit is not required by the relevant Governmental Authority prior to energization, testing and use of the Facility.

COMPANY MILESTONES

If Seller satisfies the foregoing Seller's Conditions Precedent, the following Company Milestones shall apply:

Company Milestone Date	**Description of Each Company Milestone**
2 Business Days following the Test Ready Deadline	Company shall, subject to Seller's continued satisfaction of the requirements set forth in **Section 2(f)(ii)** and **Section 2(f)(iii)** of **Attachment G** (Company-Owned Interconnection Facilities), commence Acceptance Testing.
10/3/2022	Energization of Company-Owned Interconnection Facilities, provision of back-feed power to support commissioning.

ATTACHMENT L
REPORTING MILESTONES

Reporting Milestone Date	Description of Each Reporting Milestone
1/31/2021	Seller shall provide Company with a redacted copy of the executed Facility equipment, engineering, procurement and construction, or other general contractor agreements; provided, that, under no circumstances shall redactions conceal information that is necessary for Company to verify its rights under the Agreement
6/30/2021	Seller shall provide Company with redacted copies of executed purchase orders/contracts for the delivery and installation of Facility inverters
N/A	Seller shall provide Company with copies, as applicable, of executed Facility operating agreements
1/28/2022	Construction Start Date (defined as the start of civil work on Site)
4/29/2022	Seller shall have laid the foundation for all Facility buildings and step-up transformer facilities
7/29/2022	All inverters for the Facility shall have been installed at the Site
9/30/2022	The step-up transformer shall have been installed at the Site

ATTACHMENT N

ACCEPTANCE TEST GENERAL CRITERIA[31]

Upon final completion of Company review of the Facility's drawings, final test criteria and procedures shall be agreed upon by Company and Seller no later than thirty (30) Days prior to conducting the Acceptance Test in accordance with the Agreement. The Acceptance Test shall include, but not be limited to, the following:

1. Interconnection.

(a) A visual inspection of all Interconnection equipment and verification of as-built drawings.

(b) Phase rotation testing to verify proper phase connections.

(c) Based on manufacturer's specification, test the local operation of the Facility's generator breaker(s) and inter-tie breaker(s), and other breaker(s) which connect the Facility equipment to Company System – must open and close locally using the local controls remotely from Company's EMS. Test and ensure that the status shown on the EMS is the same as the actual physical status in the field.

(d) Relay test engineers to connect equipment and simulate certain inputs to test and ensure that the protection schemes such as any under/over frequency and under/over voltage protection or the Direct Transfer Trip operate as designed. (For example, a fault condition may be simulated to confirm that the breaker opens to sufficiently clear the fault. Additional scenarios may be tested and would be outlined in the final test criteria and procedures.) Seller to also test the synchronizing mechanisms to which the Facility would be synchronizing and closing into the Company System to ensure correct operation. Other relaying also to be tested as

[31] Data and test points will not be available until the completion of the Interconnection Requirements Study ("IRS").

specified in the protection review of the IRS and on the single line diagram, **Attachment E** (Single-Line Drawing and Interface Block Diagram) for the Facility.

(e) All 69 kV breaker disconnects and other high voltage switches will be inspected to ensure they are properly aligned and operated manually or automatically (if designed).

(f) Step-Up Transformer Enclosure(s) inspections – The Step-Up Transformer Enclosure(s) may be inspected to test and ensure that the equipment that Seller has installed is installed and operating correctly based upon agreed to design. Wiring may be field verified on a sample basis against the wiring diagrams to ensure that the installed equipment is wired properly. The grounding mat at the Step-Up Transformer Enclosure(s) may be tested to make sure there is adequate grounding of equipment.

(g) Communication testing – Communication System testing to occur to ensure correct operation. Detailed scope of testing will be agreed by Company and Seller to reflect installed systems and communication paths that tie the Facility to Company's communications system.

(h) Various contingency scenarios to be tested to ensure adequate operation, including testing contingencies such as loss of communications, and fault simulations to ensure that the Facility's 69 kV breakers, if any, open as they are designed to open. (Back up relay testing)

(i) Metering section inspection; verification of metering PTs, CTs, and cabinet and the installation of the two Company meters.

2. Telephone Communication.

(a) Test to confirm Company has a direct line to the Facility control room at all times and that it is programmed correctly.

(b) Test to confirm that the Facility operators can sufficiently reach Company System Operator.

(c) Verification of dial-up telephone connection for 69 kV metering cabinet.

3. Drawings, Documentation and Equipment Warranties.

The items below are required components of the Acceptance Test and must be satisfied for successful completion of this Test.

(a) Electronic and three (3) hard copies of all Switchyard construction drawings, specifications, calibrations, and settings including as-built drawings.

(b) Equipment operating and maintenance manuals, spare parts lists, commissioning notes, as-built equipment settings, and other information related to the switchyard equipment.

(c) Contractor construction warranties and equipment warranties.

(d) Phase rotation testing to verify proper phase connections.

(e) Switching Station inspections – The Switching Station may be inspected to test and ensure that the equipment that Seller has installed is installed and operating correctly based upon agreed-to design. Wiring may be field verified on a sample basis against the wiring diagrams to ensure that the installed equipment is wired properly. The grounding mat at the Switching Station may be tested to make sure there is adequate grounding of equipment.

(f) If agreed by the Parties in writing, some requirements may be postponed to the Control Systems Acceptance Test.

ATTACHMENT O[32]

CONTROL SYSTEM ACCEPTANCE TEST CRITERIA

a. The Acceptance Test for the Facility will be conducted, following installation of the Facility. The Acceptance Test procedures will be in accordance with criteria set forth herein. The Acceptance Test shall be performed in accordance with Good Engineering and Operating Practices and demonstrate to Company's satisfaction that the Facility and the interconnection portion of the Facility, including Company-Owned Interconnection Facilities, have met the provisions of **Article 12** (Dispatching and Charging the Facility; Scheduling) and **Section 3** (Performance Standards) of **Attachment B** (Facility Owned by Seller).

b. Acceptance Test procedures will be developed by Company for the Seller's review at least sixty (60) Days in advance of performing the tests based on the date provided by Company.

c. The procedures will include, but not be limited to, demonstration of the functional requirements of the Facility defined in **Article 12** (Dispatching and Charging the Facility; Scheduling) and **Section 3** (Performance Standards) of **Attachment B** (Facility Owned by Seller) such as, but not limited to:

    i. Interconnection equipment and communications to support remote monitoring of the Facility and control of Facility breakers

    ii. Droop characteristic and change of frequency control / response modes (if applicable)

[32] Data and test points will not be available until the completion of the Interconnection Requirements Study ("IRS")

iii. Real power delivery under remote Company Dispatch, Active Power Dispatch. For facilities with directly controlled storage, the storage will be operated to perform at least two full charging/discharging cycles.

iv. Accurate provision of limits for Minimum and Maximum Dispatch (Power Possible, Minimum load capability)

v. Ramp rates for controlled actions

vi. Control of Facility breakers

vii. Voltage regulation

vii. Grid forming and Black start (if applicable)

viii. Capacity Test and demonstration of round trip efficiency of the BESS, each as described in **Attachment T** (Facility Tests)

d. Testing of primary and redundant communications between Company System Operator and Facility Operator

e. The actual dynamic response of the Facility equipment will be confirmed to allow Company transient stability model to reflect the as-left conditions of the unit. During the commissioning the following will be required:

i. A final review by Company engineers of the equipment installed to control the operation and protect the plant will be needed upon installation and prior to the start of commercial operation.

ii. The review will include off-line tuning and testing results of the excitation and governor control and/or control system and the IEEE block diagram utilized for the PSS/E dynamics program.

iii. During the commissioning of the actual Facility, equipment system testing will be conducted to ensure that similar, well damped, expected responses will be produced by the facility. The as-left parameters obtained from real and reactive local response tuning will be determined for use in the Company planning model. The Seller will provide an estimate of the earliest date for the Acceptance Test at least ninety (90) Days before the date.

f. The Acceptance Test procedures for the Facility will be mutually agreed upon between Seller and Company prior to conducting the test.

g. When the Facility is ready for the Acceptance Test, Seller shall notify Company at least seven (7) Days prior to the test and shall coordinate with Company. Seller shall perform and Company shall monitor such test no earlier than seven (7) Days from Company's receipt of such notice.

h. The Control Acceptance Test is to be successfully completed prior to the Commercial Operation Date.

Examples of the type of tests conducted to meet the aforementioned objectives may include, but are not limited to the following:

On-site Tests:

1. SCADA Test to verify the status and analog telemetry, and if the remote controls between the Company's EMS and the Facility are working properly end-to-end.

2. Dispatch Test to verify if the Facility's active power limit controls and the Active Power Control Interface with the Company's EMS are working properly. The Test is generally conducted by setting different active power setpoints and limits and observing the proper dispatch at the appropriate ramp rate limiting of the Facility's real power output.

3. Control Test for Voltage Regulation to verify the Facility can properly perform automatic voltage regulation as defined in this Agreement. Test is generally conducted by making small adjustments of the voltage setpoint and verifying by observation that the Facility regulates the voltage at the point of regulation to the setpoint by delivering/receiving reactive power to/from the Company System to maintain the applicable setpoint according to the reactive power control and the reactive amount requirements of **Sections 3(a)** (Reactive Power Control) and **Section 3(b)** (Reactive Power Characteristics) of **Attachment B** (Facility Owned by Seller) to this Agreement.
4. Frequency Response Test to verify the Facility provides a frequency droop response as defined in this Agreement. Test is generally conducted by making adjustments of the frequency reference setting and verifying by observation that the Facility responds per droop and deadband settings, and appropriately modifies the Company issued Dispatch Setpoint. If different modes of frequency response are provided, each mode is tested (i.e.; isochronous, fast frequency response, active power droop response).
5. Loss-of-Communication Test to verify the Facility will properly shutdown upon the failure of the direct-transfer-trip communication system. Test is generally conducted by simulating a communications failure and observing the proper shutdown of the Facility. [If DTT required for the project]
6. Round Trip Efficiency Test, as described in **Attachment T** (Facility Tests) to verify that the round trip efficiency of the BESS is not less than 83 percent (83%).
7. Capacity Test to verify the Capacity Ratio.

Monitoring Test:

a) The monitoring test requires the Facility to operate as it would in normal operations.

b) To ensure useful and valid test data is collected for variable facilities, the monitoring test shall end when one of the following criteria is met:

A. For variable energy resources, Facility's gross power production is greater than 85% of its Allowed Capacity, for at least four (4) hours in any continuous 24-hour CSAT period.

B. For solar facilities, the recorded renewable energy resource at the Facility is above 600 W/m^2 for at least eight (8) hours in any continuous 48-hour CSAT period.

C. For wind facilities, the recorded wind speed is sufficient for turbines to operate for at least 8 hours in any continuous 48-hour CSAT period.

D. 14 continuous Days from the start of the CSAT.

c) At the end of the test, an evaluation period is selected based on the criteria that triggered the end of the test.

d) The performance of the Facility during the period of the successfully completed monitoring test is evaluated for, e.g. voltage regulation, frequency response, dispatch control, operating limits and ramp rate performance, to verify the performance meets the requirements of this Agreement according to the criteria set forth in the testing procedures. Certain requirements, such as disturbance ride-through requirements, cannot be adequately tested without actual grid disturbances. These requirements will be confirmed following a grid event based on operational data, which may be after the completion of the Acceptance Test. The Parties understand and agree that a successful completion of the test does not constitute a waiver of any of the performance standards of Seller, all of which are hereby reserved, and shall not alleviate Seller from any of its obligations under the Agreement, in particular, as required in **Article 12** (Dispatching and Charging the Facility; Scheduling) and the Performance Standards in **Section 3** (Performance Standards) of **Attachment B** (Facility Owned by Seller).

ATTACHMENT T

FACILITY TESTS[33]

Prior to achieving Commercial Operations and in each Measurement Period, unless waived by Company, Seller shall demonstrate that the Facility satisfies the following:

- Maintains output provided by the Company through a control setpoint, as measured at the Point of Interconnection, and is able to continuously dispatch the full Contract Capacity (the "**Capacity Test**")
- Demonstrates the charging/discharging requisite to satisfy the performance standard set forth in **Section 3(w)** (Round Trip Efficiency) of **Attachment B** (Facility Owned by Seller) (the "**RTE Test**")

The RTE Test requires measurement of "Charging Energy" at the Point of Interconnection (MWh from the grid) from Facility 0% State of Charge to bring the Facility to a 100% State of Charge, followed by measurement of the MWh delivered to the grid to bring the Facility to a 0% State of Charge. The RTE Test will be conducted concurrently with the Capacity Test.

The Capacity Test can only be performed when the Facility is at the lower of: (i) its maximum State of Charge or (ii) 100% State of Charge prior to the start of the Capacity Test and during the Capacity Test the Company Dispatch/Charge allows for continuous dispatch of the Facility to 0% State of Charge with energy delivered to the Point of Interconnection.

For the purposes of evaluating the Capacity Test, the "**Capacity Ratio**" shall be equal to the number, expressed as a percentage, equal to the total MWh delivered to the Point of Interconnection during the Capacity Test, divided by the Contract Capacity. Further, the

[33] Data and test points will not be available until the completion of the Interconnection Requirements Study ("IRS")

Capacity Test will be deemed to be "passed" or "satisfied" to the extent the Capacity Ratio is not less than **100%** (the "**Capacity Performance Metric**").

For the purposes of evaluating the RTE Test, the RTE Ratio shall be equal to the number, expressed as a percentage, equal to the total MWh delivered to the Point of Interconnection during the Capacity Test, divided by the "Charging Energy" measured at the Point of Interconnection. For purposes of the RTE Test, the charging cycle shall begin when the Facility is at a 0% State of Charge prior to the commencement of the Capacity Test and the Charging Energy is the amount of energy imported from the grid, as measured at the Point of Interconnection, that brings the Facility to a 100% State of Charge. The formula is RTE Ratio = MWh discharge ÷ MWh charge. The RTE Test will be deemed to have been "passed" or "satisfied" to the extent the RTE Ratio is not less than the performance standard (the "**RTE Performance Metric**") set forth in **Section 3(w)** (Round Trip Efficiency) of **Attachment B** (Facility Owned by Seller).

Except for the Capacity Test conducted prior to Commercial Operations, Seller shall, in lieu of conducting a Capacity Test, be permitted to demonstrate satisfaction of the Capacity Performance Metric by reference to the operational data reflecting the net output of the Facility from the Point of Interconnection for such Measurement Period.

Except for the RTE Test conducted prior to Commercial Operations, Seller shall, in lieu of conducting an RTE Test, be permitted to demonstrate satisfaction of the RTE Performance Metric by reference to the operational data reflecting the charging/discharging of the Facility from the Point of Interconnection during such Measurement Period.

Any Capacity Test or RTE Test (each a "**Facility Test**" and collectively, the "**Facility Tests**"), other than where the Capacity Performance Metric or RTE Performance Metric, as applicable, is demonstrated by reference to operational data as provided below, shall be performed at a time reasonably requested by the Company in its sole discretion. Within a Measurement Period, Seller shall be permitted up to a total of three (3) Facility Tests to demonstrate satisfaction of the Capacity Performance Metric and the RTE Performance Metric for such Measurement Period, unless additional such tests are authorized by Company. Company shall provide notice to Seller no less than three (3) Business Days prior to conducting a Facility Test.

At any time prior to conducting the third (3rd) Capacity Test noticed by Company for a Measurement Period, Seller may demonstrate satisfaction of the Capacity Performance Metric by reference to operational data reflecting the net output of the Facility from the Point of Interconnection for such Measurement Period. If, during a Measurement Period, Seller both fails to pass a Capacity Test noticed by Company and fails to demonstrate satisfaction of the Capacity Performance Metric by reference to operational data for such Measurement Period, the Facility shall nevertheless be deemed to have satisfied the Capacity Performance Metric for the applicable Measurement Period if either (i) Company failed to notice at least three (3) Capacity Tests during such Measurement Period, or (ii) Seller was unable to perform at least two (2) such noticed Capacity Tests during such Measurement Period due to (a) conditions on the Company System other than Seller-Attributable Unavailability or (b) an act or omission by Company.

At any time prior to conducting the third RTE Test noticed by Company for a Measurement Period, Seller may demonstrate satisfaction of the RTE Performance Metric by reference to operational data reflecting charging/discharging of the Facility from the Point of Interconnection during such Measurement Period. If, during a Measurement Period, Seller both fails to pass a RTE Test noticed by Company and fails to demonstrate satisfaction of the RTE

Performance Metric by reference to operational data for such Measurement Period, the Facility shall nevertheless be deemed to have satisfied the RTE Performance Metric for the applicable Measurement Period if either (i) Company failed to notice at least three RTE Tests during such Measurement Period, or (ii) Seller was unable to perform at least two (2) such noticed RTE Tests during such Measurement Period due to (a) conditions on the Company System other than Seller-Attributable Unavailability or (b) an act or omission by Company.

Company shall have the right to attend, observe and receive the results of all Facility Tests. Seller shall provide to Company the results of each Facility Test (including time stamped graphs of system performance based in operational data or test data) no later than ten (10) Business Days after the performance of such Facility Test.

ATTACHMENT V
ANNUAL EQUIVALENT FORCED OUTAGE FACTOR

$$EFOF = 100\% \times \frac{(FOH + EUDH)}{8760}$$

Where:

EUDH is the equivalent unplanned (forced) derated hours. Each Unplanned (Forced) Derating of the Facility is transformed into equivalent full outage hour(s). This is calculated by multiplying the actual duration of the Deration (hours) by (i) the size of the reduction (MW) divided by (ii) the Maximum Rated Output. These equivalent hour(s) are then summed for the Measurement Period and added to the sum of the EUDH for the immediately preceding three (3) full Measurement Periods.

- (Hours of Deration x Size of Reduction) ÷ Maximum Rated Output

Forced Outage Hours (FOH) = Sum of all hours experienced during Unplanned (Forced) Outages during the applicable Measurement Period and the sum of all hours experienced during Unplanned (Forced) Outages during the immediately preceding three (3) full Measurement Periods, in each case caused by Seller-Attributable Unavailability.

Unplanned (Forced) Derating: A Deration that requires a reduction in capacity of the Facility before the end of the nearest following weekend.

Unplanned (Forced) Outage: An outage that requires removal of the entire Facility from service before the end of the nearest following weekend that is not planned.

EXAMPLE CALCULATION:

Assume a 50 MW Facility that for the Measurement Period in question was completely out of service for 50 hours. For the Measurement Period in question, it also had the following deratings:

Duration of Derating	MW Size Reduction
100 Hours	25 MW
20 Hours	20 MW
50 Hours	5 MW

During the three preceding Measurement Periods, the Facility had a total of 150 Forced Outage Hours and a total of 100 Equivalent Forced Derated Hours.

FOH = 50 hours + 150 hours = 200 hours
EUDH = [(100 x 25) ÷ 50] + [(20 x 20) ÷ 50] + [(50 x 5) ÷ 50] + 100 = 163 hours

$$EFOF = 100\% \times \frac{(200 + 163)}{8760} = 4.1\%$$

EXHIBIT 2: KEĀHOLE BESS PROJECT COST SUMMARY

COST SUMMARY

Table 1 below shows a high-level summary of the total cost estimate for the 12 MW 1-hour Contingency and Fast Frequency Response Battery Energy Storage System (BESS) project. Because this project was selected under a competitive bidding process, all cost breakdowns provided below are considered to be confidential information so as to protect the Company's competitive position.

Table 1 – BESS Project Total Cost Estimate

Item	Cost ($000s)
1. BESS EPC Contract	[redacted]
2. Owner's Cost	[redacted]
3. 69 kV Interconnection	[redacted]
4. AFUDC	[redacted]
5. Overheads	[redacted]
Total Cost	[redacted]

The following sections provide brief explanations for line items 1 through **5** in Table 1, above.

BATTERY ENGINEERING, PROCUREMENT, and CONSTRUCTION ("EPC") CONTRACT

The cost for the battery system EPC are from Tesla, who was selected based on a competitive bidding process conducted by the self-build team. The line items shown as "Covered in EPC" are major items that have been confirmed with Tesla to be included in the proposal.

Table 2 – EPC Contract Pricing

Item	Cost ($000s)
[redacted]	

OWNER's COSTS

The breakdown of labor and non-labor cost direct to Hawaiian Electric for the project is shown belowTable 2. Support of a full-time project manager is included in the costs. A contracted "owner's representative" will be onsite during the construction phase of the project. Engineering support will be needed from electrical, mechanical, structural, controls, and telecom engineering disciplines within the Company.

Table 2: Owner's Cost Breakdown

Item	Cost ($000s)
Owner's Representative	[redacted]
Project Management Labor	
Engineering Labor	
Total Owner's Cost	

INTERCONNECTION COSTS

Table 4 below shows the estimate for the interconnection of the BESS to the Keāhole Switching Station at the 69 kV level. This work is anticipated to be performed by Hawaiian Electric crews or contractors directly retained by Hawaiian Electric.

Table 4: 69 kV Keahole Switching Station Interconnection Costs

Item	Cost ($000s)
Substation Materials/Construction for Interconnection	[redacted]
T&D Materials/Construction for Interconnection	[redacted]
Total Interconnection Cost	[redacted]

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

The Allowance for Funds Used During Construction ("AFUDC") for the Project was obtained using Hawaiian Electric's budgeting software (UI Planner). The total amount of estimated AFUDC is [redacted] which represents [redacted] of the total budget.

OVERHEAD

The overhead costs for the Keāhole BESS Project were obtained using Hawaiian Electric'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. The total estimated amount of overheads represents approximately [redacted] of total project costs. Overheads are comprised of non-productive wages (such as holiday, sick, and vacation pay), employee benefits, payroll taxes, corporate administrative costs, and clearing costs.

OPERATIONS AND MAINTENANCE COSTS (O&M)

The Megapacks, Megapack Inverters, and Megapack Controllers have detailed preventative maintenance scheduled. Several system inspections, checks, and cleanings are required on an annual basis with small replacements at 5 and 10 years. The MV transformers, switchgear, and GSU also require periodic maintenance. Annual site operational costs and other expenses & fees have also been budgeted for. Annual O&M costs are provided in Exhibit 5.

SCHEDULE B1
(To file by Feb 2023)
PAGE 1 OF 2

HAWAII ELECTRIC LIGHT COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
ILLUSTRATIVE DETERMINATION OF TARGET REVENUES

Line No.	Description (a)	Reference (b)		Docket No. 2015-0170 Amounts (c)	Docket No. 2015-0170 Amounts (d)	Docket No. 2015-0170 Amounts (e)
1	Last Rate Case Annual Electric Revenue at Approved Rate Levels	Note 1	$000s	$ 289,771	$ 289,771	$ 291,358
2	Less Fuel Expense	Note 1	$000s	$ (45,996)	$ (45,996)	$ (45,996)
3	Purchased Power Expense	Note 1	$000s	$ (72,438)	$ (72,438)	$ (72,438)
4	Revenue Taxes on Line 1 (8.885% statutory rates)		$000s	$ (25,746)	$ (25,746)	$ (25,887)
5	Last Rate Order Target Annual Revenues	Sum Lines 1 thru 4	$000s	$ 145,591	$ 145,591	$ 147,037
6	Add Authorized RAM Revenues - Transmittal No. 18-02	Note 2	$000s	$ 6,577	$ -	$ -
7	Less Revenue Taxes on Line 6 at 8.885%		$000s	$ (584)	$ -	$ -
8	Net RAM Adjustment - Test Year +2	Line 6 + 7	$000s	$ 5,992	$ -	$ -
9	Authorized RAM Revenues - Transmittal No. 19-02	Note 2a	$000s	$ -	$ 7,670	$ 7,670
10	Less Revenue Taxes on Line 9 at 8.885%		$000s	$ -	$ (681)	$ (681)
11	Net RAM Adjustment - Test Year +3	Line 9 + 10	$000s	$ -	$ 6,988	$ 6,988
12	Authorized RAM Revenues	Note 5	$000s	$ -	$ -	$ -
13	Less Revenue Taxes on Line 12 at 8.885%		$000s	$ -	$ -	$ -
14	Net RAM Adjustment - Test Year +1	Line 12 + 13	$000s	$ -	$ -	$ -
15	Authorized MPIR Revenues	Note 5, Sch L	$000s	$ -	$ -	$ -
16	Less Revenue Taxes on Line 15 at 8.885%		$000s	$ -	$ -	$ -
17	Net MPIR Adjustment	Line 15 + 16	$000s	$ -	$ -	$ -
18	Less EARNINGS SHARING REVENUE CREDITS	Note 5	$000s	$ -	$ -	$ -
19	Less Revenue Taxes on Line 18 at 8.885%		$000s	$ -	$ -	$ -
20	Net Earnings Sharing Revenue Credits	Line 18 + 19	$000s	$ -	$ -	$ -
21	Less PERFORMANCE INCENTIVE MECHANISM REWARD (PENALTY)	Note 5	$000s	$ -	$ (15)	$ (15)
22	Less Revenue Taxes on Line 21 at 8.885%		$000s	$ -	$ 1	$ 1
23	Net Performance Incentive Mechanism	Lines 21 + 22	$000s	$ -	$ (14)	$ (14)
24	Less 2016 TEST YEAR FINAL D&O REFUND	Transmittal No. 19-02	$000s	$ -	$ (74)	$ (74)
25	Less Revenue Taxes on Line 24 at 8.885%		$000s	$ -	$ 7	$ 7
26	Net 2016 Test Year Final D&O Refund	Lines 24 + 25	$000s	$ -	$ (67)	$ (67)
27	Add OBF PROGRAM IMPLEMENTATION COSTS	Note 5	$000s	$ -	$ 237	$ 237
28	Less Revenue Taxes on Line 27 at 8.885%		$000s	$ -	$ (21)	$ (21)
29	Net OBF Program Implementation Costs	Lines 27 + 28	$000s	$ -	$ 216	$ 216
30	PUC-ORDERED MAJOR OR BASELINE CAPITAL CREDITS	Note 5	$000s	$ -	$ -	$ -
31	Total Annual Target Revenues					
32	June 1, 2018 Annualized Revenues + RAM Increase	Lines (5+8)	$000s	$ 151,583		
33	June 1, 2019 Annualized Revenues + RAM Increase	Lines (5+11+17+23+26+29+30)	$000s		$ 152,714	
34	June 1, 2019 Annualized Revenues + RAM Increase, adjusted for removal of Tax Act Implementation lag effective Nov 1, 2019	Lines (5+11+17+20+ 23+26+29+30)	$000s			$ 154,160
35	Interim D&O, dated November 13, 2019 Annualized Revenues w/ Zero Interim Increase & MPIR accrued 1/1/2020	Lines (5+17+20+ 23+26+29+30)	$000s			
36	Interim D&O, dated November 13, 2019 Annualized Revenues w/ Zero Interim Increase + RAM & MPIR accrued 1/1/2020	Lines (5+14+17+20+ 23+26+29+30)	$000s			
37	June 1, 2020 Annualized Revenues w/ RAM increase & MPIR accrued 1/1/2023	Lines (5+14+17+20+ 23+26+29+30)	$000s			
38	Distribution of Target Revenues by Month	Note 3	Note 4	2019	2019	2019
39	January	8.437%	8.493%	$ 12,789,089		
40	February	7.898%	7.673%	$ 11,972,055		
41	March	8.410%	8.493%	$ 12,748,162		
42	April	8.072%	8.219%	$ 12,235,810		
43	May	8.292%	8.493%	$ 12,569,293		
44	June	8.081%	8.219%		$ 12,340,796	
45	July	8.630%	8.493%		$ 13,179,194	
46	August	8.764%	8.493%		$ 13,383,830	
47	September	8.213%	8.219%		$ 12,542,378	
48	October	8.548%	8.493%		$ 13,053,969	
49	November	8.263%	8.219%			$ 12,738,218
50	December	8.392%	8.493%			$ 12 937 084
51	Total Distributed Target Revenues	100.00%	100.00%	$ 62,314,409	$ 64,500,167	$ 25,675,302

Note Amounts may not foot due to rounding.

Note 1 Col. c, d Order No. 35419 Granting Motion to Adjust Interim Increase, issued on April 24, 2018 in Docket No. 2015-0170. Target Revenue calculation is provided in HELCO Revision to Exhibits in Motion to Adjust Interim Increase, Exhibit 14, page 2 of 2 filed April 10, 2018. Approved in Final Decision and Order No. 35559, filed June 29, 2018.
Col. e Final D&O 35559 in Docket No. 2015-0170, filed June 29, 2018, the Commission approved the adjustment to Target Revenue to remove the reduction for the Tax Implementation Lag of $1,587,000 effective November 1, 2019 as the Company amortized the lag over 18 months through October 31, 2019.
Col f, g, h Interim Decision and Order No. 36761, filed on November 13, 2019, in Docket No. 2018-0368 ("Hawai'i Electric Light 2019 Interim D&O") approving HELCO Statement of Probable Entitlement, Attachment 5, filed October 1, 2019.

Note 2 Transmittal 18-02 filed May 29, 2018, establishing 2018 target revenue effective June 1, 2018.

Note 2a Transmittal 19-02 filed May 28, 2019, establishing 2019 target revenue effective June 1, 2019.

Note 3 HELCO RBA Provision Tariff effective August 31, 2017 based on 2016 test year, filed on July 30, 2018 in Docket No. 2015-0170. The Commission approved the final tariff sheets in Order No. 35709 of Docket No. 2015-0170 on September 21, 2018.

Note 4 Monthly Allocation Factors based on the number of days in the month as a percentage of the number of days in the year, with the allocation factor for February set such that the total of the monthly allocation factors sums to 100%. Effective January 2020.

Note 5 Transmittal Nos. 20-01, 20-02, 20-03 Consolidated (Decoupling) - 2020 RBA Rate Adjustment, approved in Order No. 37150, filed May 28, 2020 updated target revenues for the removal of Phase 1 Grid Modernization project withholdings approved in Order No. 37146, Docket 2018-0141, retroactive to January 1, 2020.

Note 6 FOR ILLUSTRATION PURPOSES ONLY - MPIR Revenue accrual starting January 1, 2023 filed in Transmittal xx-xx, filed Month Day, Year.

HAWAII ELECTRIC LIGHT COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
ILLUSTRATIVE DETERMINATION OF TARGET REVENUES

Line No.	Description (a)	Reference (b)		Interim D&O No. 36761 Docket No. 2018-0368 Amounts (f)	Interim D&O No. 36761 Docket No. 2018-0368 Amounts (g)	Interim D&O No. 36761 Docket No. 2018-0368 Amounts (h)	Note (6) MPIR ILLUSTRATIVE EFFECTIVE 1/1/2023 (i)
1	Last Rate Case Annual Electric Revenue at Approved Rate Levels	Note 1	$000s	$ 169,045	$ 169,045	$ 169,045	$ 169,045
2	Less Fuel Expense	Note 1	$000s	$ -	$ -	$ -	$ -
3	Purchased Power Expense	Note 1	$000s	$ -	$ -	$ -	$ -
4	Revenue Taxes on Line 1 (8.885% statutory rates)		$000s	$ (15,020)	$ (15,020)	$ (15,020)	$ (15,020)
5	Last Rate Order Target Annual Revenues	Sum Lines 1 thru 4	$000s	$ 154,025	$ 154,025	$ 154,025	$ 154,025
6	Add Authorized RAM Revenues - Transmittal No. 18-02	Note 2	$000s	$ -	$ -	$ -	$ -
7	Less Revenue Taxes on Line 6 at 8.885%		$000s	$ -	$ -	$ -	$ -
8	Net RAM Adjustment - Test Year +2	Line 6 + 7	$000s	$ -	$ -	$ -	$ -
9	Authorized RAM Revenues - Transmittal No. 19-02	Note 2a	$000s	$ -	$ -	$ -	$ -
10	Less Revenue Taxes on Line 9 at 8.885%		$000s	$ -	$ -	$ -	$ -
11	Net RAM Adjustment - Test Year +3	Line 9 + 10	$000s	$ -	$ -	$ -	$ -
12	Authorized RAM Revenues	Note 5	$000s	$ -	$ 3,212	$ 3,212	$ 3,212
13	Less Revenue Taxes on Line 12 at 8.885%		$000s	$ -	$ (285)	$ (285)	$ (285)
14	Net RAM Adjustment - Test Year +1	Line 12 + 13	$000s	$ -	$ 2,926	$ 2,926	$ 2,926
15	Authorized MPIR Revenues	Note 5, Sch L	$000s	$ 62	$ 62	$ 62	[redacted]
16	Less Revenue Taxes on Line 15 at 8.885%		$000s	$ (6)	$ (6)	$ (6)	
17	Net MPIR Adjustment	Line 15 + 16	$000s	$ 57	$ 57	$ 57	
18	Less EARNINGS SHARING REVENUE CREDITS	Note 5	$000s	$ -	$ -	$ -	$ -
19	Less Revenue Taxes on Line 18 at 8.885%		$000s	$ -	$ -	$ -	$ -
20	Net Earnings Sharing Revenue Credits	Line 18 + 19	$000s	$ -	$ -	$ -	$ -
21	Less PERFORMANCE INCENTIVE MECHANISM REWARD (PENALTY)	Note 5	$000s	$ (15)	$ (156)	$ (156)	$ (156)
22	Less Revenue Taxes on Line 21 at 8.885%		$000s	$ 1	$ 14	$ 14	$ 14
23	Net Performance Incentive Mechanism	Lines 21 + 22	$000s	$ (14)	$ (142)	$ (142)	$ (142)
24	Less 2016 TEST YEAR FINAL D&O REFUND	Transmittal No. 19-02	$000s	$ (74)	$ -	$ -	$ -
25	Less Revenue Taxes on Line 24 at 8.885%		$000s	$ 7	$ -	$ -	$ -
26	Net 2016 Test Year Final D&O Refund	Lines 24 + 25	$000s	$ (67)	$ -	$ -	$ -
27	Add OBF PROGRAM IMPLEMENTATION COSTS	Note 5	$000s	$ 237	$ 239	$ 239	$ 239
28	Less Revenue Taxes on Line 27 at 8.885%		$000s	$ (21)	$ (21)	$ (21)	$ (21)
29	Net OBF Program Implementation Costs	Lines 27 + 28	$000s	$ 216	$ 218	$ 218	$ 218
30	PUC-ORDERED MAJOR OR BASELINE CAPITAL CREDITS	Note 5	$000s	$ -	$ -	$ -	$ -
31	Total Annual Target Revenues						
32	June 1, 2018 Annualized Revenues + RAM Increase	Lines (5+8)	$000s				
33	June 1, 2019 Annualized Revenues + RAM Increase	Lines (5+11+17+23+26+29+30)	$000s				
34	June 1, 2019 Annualized Revenues + RAM Increase, adjusted for removal of Tax Act Implementation lag effective Nov 1, 2019	Lines (5+11+17+20+ 23+26+29+30)	$000s				
35	Interim D&O, dated November 13, 2019 Annualized Revenues w/ Zero Interim Increase & MPIR accrued 1/1/2020	Lines (5+17+20+ 23+26+29+30)	$000s	$ 154,217			
36	Interim D&O, dated November 13, 2019 Annualized Revenues w/ Zero Interim Increase + RAM & MPIR accrued 1/1/2020	Lines (5+14+17+20+ 23+26+29+30)	$000s		$ 157,084	$ 157,084	
37	June 1, 2020 Annualized Revenues w/ RAM increase & MPIR accrued 1/1/2023	Lines (5+14+17+20+ 23+26+29+30)	$000s				[redacted]

Line No.	Description	Note 3	Note 4	Note (5) 2020	2020	2021	Note (6) 2023
38	Distribution of Target Revenues by Month						[redacted]
39	January	8.437%	8.493%	$ 13,097,623		$ 13,341,144	
40	February	7.898%	7.673%	$ 11,833,046		$ 12,053,055	
41	March	8.410%	8.493%	$ 13,097,623		$ 13,341,144	
42	April	8.072%	8.219%	$ 12,675,069		$ 12,910,734	
43	May	8.292%	8.493%	$ 13,097,623		$ 13,341,144	
44	June	8.081%	8.219%		$ 12,910,734		
45	July	8.630%	8.493%		$ 13,341,144		
46	August	8.764%	8.493%		$ 13,341,144		
47	September	8.213%	8.219%		$ 12,910,734		
48	October	8.548%	8.493%		$ 13,341,144		
49	November	8.263%	8.219%		$ 12,910,734		
50	December	8.392%	8.493%		$ 13 341 144		
51	Total Distributed Target Revenues	100.00%	100.00%	$ 63,800,984	$ 92,096,778	$ 64,987,221	

Note Amounts may not foot due to rounding.

Note 1 Col. c, d Order No. 35419 Granting Motion to Adjust Interim Increase, issued on April 24, 2018 in Docket No. 2015-0170. Target Revenue calculation is provided in HELCO Revision to Exhibits in Motion to Adjust Interim Increase, Exhibit 14, page 2 of 2 filed April 10, 2018. Approved in Final Decision and Order No. 35559, filed June 29, 2018.
Col. e Final D&O 35559 in Docket No. 2015-0170, filed June 29, 2018, the Commission approved the adjustment to Target Revenue to remove the reduction for the Tax Implementation Lag of $1,587,000 effective November 1, 2019 as the Company amortized the lag over 18 months through October 31, 2019.
Col f, g, h Interim Decision and Order No. 36761, filed on November 13, 2019, in Docket No. 2018-0368 ("Hawai'i Electric Light 2019 Interim D&O") approving HELCO Statement of Probable Entitlement, Attachment 5, filed October 1, 2019.

Note 2 Transmittal 18-02 filed May 29, 2018, establishing 2018 target revenue effective June 1, 2018.

Note 2a Transmittal 19-02 filed May 28, 2019, establishing 2019 target revenue effective June 1, 2019.

Note 3 HELCO RBA Provision Tariff effective August 31, 2017 based on 2016 test year, filed on July 30, 2018 in Docket No. 2015-0170. The Commission approved the final tariff sheets in Order No. 35709 of Docket No. 2015-0170 on September 21, 2018.

Note 4 Monthly Allocation Factors based on the number of days in the month as a percentage of the number of days in the year, with the allocation factor for February set such that the total of the monthly allocation factors sums to 100%. Effective January 2020.

Note 5 Transmittal Nos. 20-01, 20-02, 20-03 Consolidated (Decoupling) - 2020 RBA Rate Adjustment, approved in Order No. 37150, filed May 28, 2020 updated target revenues for the removal of Phase 1 Grid Modernization project withholdings approved in Order No. 37146, Docket 2018-0141, retroactive to January 1, 2020.

Note 6 FOR ILLUSTRATION PURPOSES ONLY - MPIR Revenue accrual starting January 1, 2023 filed in Transmittal xx-xx, filed Month Day, Year.

SCHEDULE L
(To file by Feb 2023)
PAGE 1 OF 1

HAWAII ELECTRIC LIGHT COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
ILLUSTRATIVE MAJOR PROJECT INTERIM RECOVERY

The purpose of this Illustration is to reflect the inclusion of the Keahole BESS Project in Year 2 as part of the February 2023 annual MPIR true-up filing which will also include an update for all MPIR project costs recorded as of December 31, 2022 and 2023 activity.

Line No.	Description	Reference	Amount $000
	(a)	(b)	(c)
1	Grid Mod Phase 1 Project Docket No. 2018-0141	Note 1	$ 57
2	Keahole BESS Project Docket No. xxxx-xxxx	Schedule L2	[redacted]
3	Total MPIR Recovery		[redacted]
4	Revenue Tax Factor (1/(1-8.885%))		1.0975
5	Major Project Interim Recovery Total		[redacted] ***To Sch B1***

Note 1: Transmittal No. 20-01, 20-02, 20-03 Consolidated (Decoupling) - 2020 RBA Rate Adjustment, Attachment 2, Schedule L, filed June 5, 2020.

SCHEDULE L2
(To file by Feb 2023)
PAGE 1 OF 1

The purpose of this Illustration is to reflect Year 2 of the project filed as part of the annual MPIR true-up filing to be filed no later than February 2023 The Illustration starts with 2022 recorded costs plus 2023 activity MPIR to be in effect until such costs are reflected in base rates

HAWAII ELECTRIC LIGHT COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF MAJOR PROJECT INTERIM RECOVERY
ILLUSTRATIVE MPIR PROJECT - KEAHOLE BESS
($ in Thousands)

To the extent that recovery via the test year varies from actual costs incurred, a MPIR true-up adjustment will be made in the subsequent annual MPIR true-up filing

Line No	Description	Reference	Recorded at 12/31/2022	2023 Activity	Ending Balance as of 12/31/2023	Average Balance	MPIR
	(a)	(b)	(c)	(d)	(e)	(f)=((c)+(e))/2	(g)
	Return on Investment - Keahole BESS						
1	Plant in Service (not to exceed PUC approved amount)	*Schedule L2.1*	[redacted]	-	[redacted]	[redacted]	
2	Accum Depreciation	*HELCO-WP-L2-001*	[redacted]				
3	Net Cost of Plant in Service						
4	ADIT	*HELCO-WP-L2-002 p.1*					
5	State ITC	*HELCO-WP-L2-002 p.3*					
6	Total Deductions						
7	Total Rate Base						
8	Average Rate Base					[redacted]	
9	Rate of Return (grossed-up for income taxes, before revenue taxes)	Note 2				9 43%	
10	Annualized Return on Investment (before revenue taxes)	Rate of Return: Will be revised to reflect the most recent rate case rate of return					[redacted]
11	Depreciation Expense (Note 1)	*HELCO-WP-L2-001*				[redacted]	
11a	Amortization Expense	Not Applicable				-	
12	Operating & Maintenance Expense	Estimated; Note 3				[redacted]	
12a	Reconciliation of test year O&M to prior year actual O&M	Not Applicable				-	
13	Amortization of State ITC	Line 6, Col (d)				[redacted]	
14	Lease Rent Expense	Not Applicable				-	
15	Other Expense	Not Applicable				-	
16	Total Expenses						[redacted]
17	Total Annualized Major Project Interim Recovery						[redacted]
							To Sch L

Note 1: Depreciation expense is recorded beginning in the year after an asset is placed in service, therefore, depreciation expense is zero in year 1 The revenue requirement for year 2 and thereafter will include depreciation expense at existing, approved depreciation accrual rates at the time of filing See further discussion at HELCO-WP-L2-001

Note 2: Transmittal No 20-01, 20-02, 20-03 Consolidated (Decoupling) - 2020 RBA Rate Adjustment, Attachment 2, Schedule D, filed June 5, 2020

Note 3: Requesting PUC approval for incremental, on-going post in-service O&M costs per Exhibit 6, page 4

SCHEDULE L2.1
(To file by Feb 2023)
PAGE 1 OF 1

HAWAII ELECTRIC LIGHT COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF MAJOR PROJECT INTERIM RECOVERY
ILLUSTRATIVE MPIR PROJECT DETAIL
($ in Thousands)

Line No.	Grandparent # or Project #	Description	Docket No.	Actual In Service Date	Recorded at In Service Date
	(a)	(b)	(c)	(d)	(e)
1	HZ.005027	Keahole BESS	Docket No. xxxx-xxxx	Dec 2022	16,921
2		**Total Project Costs**			**16,921**
					To Sch L2

Source: HELCO-WP-L2-001

HAWAII ELECTRIC LIGHT COMPANY, INC.
KEAHOLE BESS
2023 Major Projects Interim Recovery Depreciation Summary - ESTIMATE

To the extent that recovery via the test year varies from actual costs incurred, a MPIR true-up adjustment will be made in the subsequent annual MPIR true-up filing.

[1] Project #	[1] Project	Project Type	Date In Service	[1] Actual Net Plant Adds Thru 12/31/21	2022 Activity	[1] Actual Net Plant Adds Thru 12/31/22	Plant Acct	[2] PUC Approved Accrual Rate	[3] 2023 Depr
				(A)	(B)	(C) = (A) + (B)		(D)	(E) = (C) * (D)
HZ 005027	Transmission - 69 kV	Project	Dec 2022	-	[redacted]	[redacted]	353	[redacted]	[redacted]
HZ 005027	Substation	Project	Dec 2022		[redacted]	[redacted]	353	[redacted]	[redacted]
HZ 005027	BESS System	Project	Dec 2022	-	[redacted]	[redacted]	348 [4]	[redacted] [4]	[redacted]
				-	16,920,865	16,920,865			[redacted]
						To Sch L2.1		*To Sch L2 / HELCO-WP-L2-002 p.1*	

[1] Source: Schedule L2 1

[2] Depreciation rates applied will be per the latest Commission rate case order
Per Docket No 2016-0431, filed July 30, 2018, consolidated depreciation and amortization rates and revised CIAC amortization period will be effective with the date of interim or final rates in the Company's subsequent general rate case proceedings, beginning with MECO's ongoing 2018 test year general rate case (or HELCO's 2019 test year)

[3] Included in MPIR recovery until total project costs are reflected in the next test year rate case base rates

[4] The BESS system component of the project should be included in plant account # 348 - Energy Storage Equipment - Production The Company will request in this Application that we are establishing a new asset category for accounting purposes: FERC Uniform System of Accounts plant account 348 00 Energy Storage Equipment – Production in accordance with the Commission's Decision and Order in the Hawaiian Electric Companies' most recent depreciation rates proceeding The Company will also request for special accounting treatment to depreciate the battery related cost over 20 years (or 5% annually) as used in the RFP and revenue requirements for the the annual depreciation expense

Confidential Information Deleted
Pursuant to Protective Order No. ____

HAWAII ELECTRIC LIGHT COMPANY, INC.
KEAHOLE BESS
ADIT
DECEMBER 31, 2022 ESTIMATE

To the extent that recovery via the test year varies from actual costs incurred, a MPIR true-up adjustment will be made in the subsequent annual MPIR true-up filing.

		Source	2022 Tax	AFUDC	Tax Capitalized Interest	State ITC	2022 Total	2023 Depreciation	State ITC	2023 Total
	FEDERAL DEFERRED TAXES									
1	Tax Difference		[redacted]							
2	Add back Book Depreciation	*HELCO-WP-L2-001*								
3	State ITC amortization	*From Page 3*								
4	Subtotal	Line 1 + 2 + 3								
5	Effective Federal Tax Rate		19.7368%	19.7368%	19.7368%	19.7368%	19.7368%	19.7368%	19.7368%	19.7368%
6	Total Federal Deferred Taxes	Line 4 * Line 5	[redacted]							
	STATE DEFERRED TAXES									
7	Tax Difference	Line 1	[redacted]							
8	Add back Book Depreciation	Line 2								
9	State ITC amortization	Line 3								
10	Subtotal	Line 7 + 8 + 9								
11	Effective State Tax Rate		6.0150376%	6.0150376%	6.0150376%	6.0150376%	6.0150376%	6.0150376%	6.0150376%	6.0150376%
12	Total State Deferred Taxes	Line 10 * Line 11	[redacted]							
13	**TOTAL DEFERRED TAXES**	Line 6 + Line 12								
							To Sch L2			*To Sch L2*
									Cumulative	[redacted]
										To Sch L2

* ADIT calculation resulting from the December 2022 plant additions will be included in the annual MPIR true-up filing to be filed no later than February 2023.

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Pursuant to Protective Order No. ____

HAWAII ELECTRIC LIGHT COMPANY, INC.
KEAHOLE BESS
TAX DEPRECIATION
DECEMBER 31, 2022 ESTIMATE

To the extent that recovery via the test year varies from actual costs incurred, a MPIR true-up adjustment will be made in the subsequent annual MPIR true-up filing.

Project No.	Description	Book Basis	Less: AFUDC	Add: TCI	*From Page 5* Tax Basis	Plant Acct	Tax Life	Note 1 Year 1 2022	Note 1 Year 2 2023
HZ.005027	Transmission - 69 kV	[redacted]				353	[redacted]	[redacted]	
HZ.005027	Substation					353			
HZ.005027	BESS System					348 [1]	2]		
	Total	16,920,865	[redacted]						
								To Page 1	*To Page 1*

Note: No bonus depreciation on public utility property placed in service after 12/31/17.
Note 1: Depreciation rate for recovery period is per IRS Publication 946, Table A-1

[1] The BESS system component of the project should be included in plant account # 348 - Energy Storage Equipment - Production. The Company will request in this Application that we are establishing a new asset category for accounting purposes: FERC Uniform System of Accounts plant account 348.00 Energy Storage Equipment – Production in accordance with the Commission's Decision and Order in the Hawaiian Electric Companies' most recent depreciation rates proceeding. The Company will also request for special accounting treatment to depreciate the battery related cost over 20 years (or 5% annually) as used in the RFP and revenue requirements for the the annual depreciation expense.

[2] The BESS system is qualify as 7-year property for tax under §168(e)(3)(C)(v) with no class life.

HAWAII ELECTRIC LIGHT COMPANY, INC.
KEAHOLE BESS
TAX CREDITS
DECEMBER 31, 2022 ESTIMATE

To the extent that recovery via the test year varies from actual costs incurred, a MPIR true-up adjustment will be made in the subsequent annual MPIR true-up filing.

State ITC Calculation

Total Materials & Outside Construction	[redacted]	***From Page 5***
State ITC %	4%	
State ITC	[redacted]	***To Sch L2***
Book Amort of State ITC	[redacted]	***To Sch L2***
State ITC, ending balance	[redacted]	***o Sch L2***

Note: 10 year State ITC tax amortization begins the year after an asset is placed in service.

HAWAII ELECTRIC LIGHT COMPANY, INC.
KEAHOLE BESS
AFUDC/TCI
DECEMBER 31, 2022 ESTIMATE

To the extent that recovery via the test year varies from actual costs incurred, a MPIR true-up adjustment will be made in the subsequent annual MPIR true-up filing.

		From Page 5	0.650138
Project #	Description	AFUDC	TCI
HZ.005027	Transmission 69 kV	[redacted]	
HZ.005027	Substation		
HZ.005027	BESS System		
Total AFUDC			

Source: Tax Return workpapers
Annual - TCI Incurred to AFUDC Incurred Ratio

	2015	2016	2017	2018	2019 Accrual	5 Yr Ave
TCI	[redacted]					
AFUDC						
Ratio	[redacted]					

To Page 5

HAWAII ELECTRIC LIGHT COMPANY, INC.
KEAHOLE BESS
COSTS BY YEAR
DECEMBER 31, 2022 ESTIMATE

To the extent that recovery via the test year varies from actual costs incurred, a MPIR true-up adjustment will be made in the subsequent annual MPIR true-up filing.

Description	Transmission 69 kV	Substation	BESS System	Total	
AFUDC	[redacted]				*To Page 4*
LABOR					
MATERIALS					
OS CONTRACTS					[redacted]
OTHER: OTHER COSTS					*To Page 3*
OVERHEAD					
Total	[redacted]			16,920,865	
Less: AFUDC	[redacted]				
Add: TCI	[redacted]				
0.650138					
From Page 4					
Tax Basis	[redacted]				*To Page 2*

Source: UI Planner

EXHIBIT 4: KEAHOLE BESS SITE PLAN VIEW

EXHIBIT 4: KEAHOLE GENERATING STATION SITE PLAN VIEW

Keahole Self Build Battery Energy Storage System (BESS) Rev Req and Bill Impact
Summary

		Keahole Self Build BESS					
		Capital	O&M	Total			
	Year	Revenue Requirement	Revenue Requirement	Revenue Requirement	Sales Forecast [1] (MWh)	Rate Impact cents per kWh	Bill Impact 500 kwh [2]
		a	b	c = sum	d	e = (c*100)/(d*1000)	g = e*5
1	2022	[redacted]			1,015,166	[redacted]	
2	2023				1,007,722		
3	2024				1,003,614		
4	2025				996,024		
5	2026				989,187		
6	2027				982,246		
7	2028				982,973		
8	2029				978,219		
9	2030				977,491		
10	2031				977,693		
11	2032				980,258		
12	2033				978,330		
13	2034				981,199		
14	2035				988,996		
15	2036				999,038		
16	2037				1,005,152		
17	2038				1,013,498		
18	2039				1,023,641		
19	2040				1,038,353		
20	2041				1,047,686		
Total		[redacted]				*Average*	$ 0.86
NPV @	7.00%	[redacted]					

Notes:
1. Estimated Hawaii Electric Light Sales Forecast from Forecasting Department.
2. Hawaii Electric Light typical residen ial energy consumption, per month.

Keahole Self Build Battery Energy Storage System (BESS) Rev Req and Bill Impact
Revenue Requirements Model
Assumptions

Manual input
HELCO TY2019 Rate Case Dkt 2018-0368 PUC Interim D&O 36761

Cost of Capital Assumptions[5]	Weight	Rate	Weighted Average	After-Tax Weighted Average	Weighted Average Revenue Requirement	Weighted Average Gross-up for Income Taxes
Short Term Debt	0.61%	3.75%	0.023%	0.02%	0.025%	0.02%
Long Term Debt (Taxable Debt)	40.59%	4.79%	1.944%	1.44%	2.134%	1.94%
Hybrids	0.80%	7.83%	0.063%	0.05%	0.069%	0.06%
Preferred Stock	1.17%	8.12%	0.095%	0.09%	0.140%	0.13%
Common Stock	56.83%	9.50%	5.399%	5.40%	7.980%	7.27%
	100.00%		7.524%	7.001%	10.348%	9.429%

Tax Assumptions		Effective
Federal Income Tax Rate	21.00%	19.74%
State Income Tax Rate	6.40%	6.02%
		25.75%

State Investment Tax Credit (ITC)[1]	4.00%	
Accelerated State ITC Amortization Period[1]	10	
Public Service Company Tax	5.885%	
PUC Fee	0.500%	
Franchise Tax	2.500%	
Composite Revenue Tax Rate	8.885%	1.09751

Project Assumptions

		Plant Add Date
Capital Investment[2]	$ 16,920,865	2022
Cost Recovery	MPIR	

Depreciation

Expected Useful Life[3]	20	
MACRS Tax Life ("Tax Life")[4]	7	half-year convention, table A-1
Tax Class Life ("Class Life")	12	half-year convention, table A-8

O&M

O&M	[redacted]	See Calculation - O&M Tab
Escalation Rate	2.0%	

Notes
1. Per HELCO 2019 TY Rate Rate Case Interim D&O 36761 in Docket No. 2018-0368, State ITC Amortization is accelerated over a ten-year period.
2. Capital Investment costs provided by Project Management.
3. Expected useful life per Tesla Bid and confirmed with HL Engineering.
4. Tax Life for BESS connected to grid is 7 years per HEI Taxes.
5. O&M costs are from Power Supply Engineering, see O&M Costs tab.

Keahole Self Build Battery Energy Storage System (BESS) Rev Req and Bill Impact — Tax Depreciation

Tax Depreciation Factors

Manual input	Years	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Tax Depreciation Rates (Straight Line)																											
	-																										
	3	16.670%	33.330%	33.330%	16.670%																						
	5	10.000%	20.000%	20.000%	20.000%	20.000%	10.000%																				
	7	7.140%	14.290%	14.290%	14.280%	14.290%	14.280%	14.290%	7.140%																		
	10	5.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	5.000%															
	15	3.330%	6.670%	6.670%	6.670%	6.670%	6.670%	6.670%	6.660%	6.670%	6.660%	6.670%	6.660%	6.670%	6.660%	6.670%	3.330%										
	20	2.500%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	2.500%					
	25	2.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	2.000%
	28	1.786%	3.571%	3.571%	3.571%	3.571%	3.571%	3.572%	3.571%	3.572%	3.571%	3.572%	3.571%	3.572%	3.571%	3.572%	3.571%	3.572%	3.571%	3.572%	3.571%	3.572%	3.571%	3.572%	3.571%	3.572%	3.571%
	30	1.667%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.334%	3.333%	3.334%	3.333%	3.334%	3.333%	3.334%	3.333%	3.334%	3.333%	3.334%	3.333%	3.334%	3.333%
	35	1.429%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%
	50	1.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%
Source: IRS Publication 946, Table A-8																											
Tax Depreciation Rates (MACRS)																											
	-																										
	3	33.330%	44.450%	14.810%	7.410%																						
	5	20.000%	32.000%	19.200%	11.520%	11.520%	5.760%																				
	7	14.290%	24.490%	17.490%	12.490%	8.930%	8.920%	8.930%	4.460%																		
	10	10.000%	18.000%	14.400%	11.520%	9.220%	7.370%	6.550%	6.550%	6.560%	6.550%	3.280%															
	15	5.000%	9.500%	8.550%	7.700%	6.930%	6.230%	5.900%	5.900%	5.910%	5.900%	5.910%	5.900%	5.910%	5.900%	5.910%	2.950%										
	20	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	2.231%					
Source: IRS Publication 946, Table A-1																											

Keahole Self Build Battery En
Tax Depreciation Factors

Tax Depreciation

Manual input	Years	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41
Tax Depreciation Rates (Str																
	-															
	3															
	5															
	7															
	10															
	15															
	20															
	25															
	28	3.572%	3.571%	1.786%												
	30	3.334%	3.333%	3.334%	3.333%	1.667%										
	35	2.857%	2.858%	2.857%	2.858%	2.857%	2.858%	2.857%	2.858%	2.857%	1.429%					
	50	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%
Source: IRS Publication 946, Ta																
Tax Depreciation Rates (MA																
	-															
	3															
	5															
	7															
	10															
	15															
	20															
Source: IRS Publication 946, Ta																

Manual input	Years	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57
Tax Depreciation Rates (Str																	
	-																
	3																
	5																
	7																
	10																
	15																
	20																
	25																
	28																
	30																
	35																
	50	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	1.000%						
Source: IRS Publication 946, Ta																	
Tax Depreciation Rates (MA																	
	-																
	3																
	5																
	7																
	10																
	15																
	20																
Source: IRS Publication 946, Ta																	

Keahole Self Build Battery En
Tax Depreciation Factors

Manual input	Years	58	59	60	Total
Tax Depreciation Rates (Str					
	-				
	3				100.000%
	5				100.000%
	7				100.000%
	10				100.000%
	15				100.000%
	20				100.000%
	25				100.000%
	28				100.000%
	30				100.000%
	35				100.000%
	50				100.000%
Source: IRS Publication 946, Ta					
Tax Depreciation Rates (MA					
	-				
	3				100.000%
	5				100.000%
	7				100.000%
	10				100.000%
	15				100.000%
	20				100.000%
Source: IRS Publication 946, Ta					

EXHIBIT 5
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Keahole Self Build Battery Energy Storage System (BESS) Rev Req and Bill Impact

O&M Revenue Requirement

	Year	Escalation	O&M[1]	O&M Revenue Requirement Factor	O&M Revenue Requirement
1	**2022**	1.00	[redacted]	1.09751	[redacted]
2	**2023**	1.00		1.09751	
3	**2024**	1.00		1.09751	
4	**2025**	1.00		1.09751	
5	**2026**	1.00		1.09751	
6	**2027**	1.00		1.09751	
7	**2028**	1.00		1.09751	
8	**2029**	1.00		1.09751	
9	**2030**	1.00		1.09751	
10	**2031**	1.00		1.09751	
11	**2032**	1.00		1.09751	
12	**2033**	1.00		1.09751	
13	**2034**	1.00		1.09751	
14	**2035**	1.00		1.09751	
15	**2036**	1.00		1.09751	
16	**2037**	1.00		1.09751	
17	**2038**	1.00		1.09751	
18	**2039**	1.00		1.09751	
19	**2040**	1.00		1.09751	
20	**2041**	1.00		1.09751	
	Total		[redacted]		[redacted]
		Check	-		

Notes:

1. Includes escalated total costs and CMA, see O&M Costs tab.

Keahole Self Build Battery Energy Storage System (BESS) Rev Req and Bill Impact

Revenue Requirements Model - Calculations

		1	2	3	4	5	6	7	8	9	10	11	12
Manual input													
O&M													
Escalation Rate		1.00	1.00	1.00	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20
O&M		-	-	-	-	-	-	-	-	-	-	-	-
Plant Asset Depreciation													
Book Depreciation													
Book Depreciation Rates		0.000%	5.263%	5.263%	5.263%	5.263%	5.263%	5.263%	5.263%	5.263%	5.263%	5.263%	5.263%
Depreciation Expense		-	890,572	890,572	890,572	890,572	890,572	890,572	890,572	890,572	890,572	890,572	890,572
Accumulated Depreciation		-	890,572	1,781,144	2,671,716	3,562,287	4,452,859	5,343,431	6,234,003	7,124,575	8,015,147	8,905,718	9,796,290
Tax Depreciation													
Tax Depreciation Rates (Straight Line)	12	5.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	5.000%	0.000%
Tax Basis (S/L)	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation Rates (MACRS)	7	14.290%	24.490%	17.490%	12.490%	8.930%	8.920%	8.930%	4.460%	0.000%	0.000%	0.000%	0.000%
NonRB Financed Tax Basis (MACRS)	100.0%	2,417,992	4,143,920	2,959,459	2,113,416	1,511,033	1,509,341	1,511,033	754,671	-	-	-	-
Tax Depreciation		2,417,992	4,143,920	2,959,459	2,113,416	1,511,033	1,509,341	1,511,033	754,671	-	-	-	-
Accumulated Tax Depreciation		2,417,992	6,561,911	9,521,371	11,634,787	13,145,820	14,655,161	16,166,194	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
State Investment Tax Credit (ITC)													
Book													
State ITC Amortization Rate		0.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	0.000%
Amortization of State ITC	4.00%	-	67,683	67,683	67,683	67,683	67,683	67,683	67,683	67,683	67,683	67,683	-
Accumulated Amortization		-	67,683	135,367	203,050	270,734	338,417	406,101	473,784	541,468	609,151	676,835	676,835
Deferred ITC		676,835	609,151	541,468	473,784	406,101	338,417	270,734	203,050	135,367	67,683	-	-
Tax		676,835											
Deferred Tax Calculation													
Book Accumulated Depreciation		-	890,572	1,781,144	2,671,716	3,562,287	4,452,859	5,343,431	6,234,003	7,124,575	8,015,147	8,905,718	9,796,290
Tax Accumulated Depreciation		2,417,992	6,561,911	9,521,371	11,634,787	13,145,820	14,655,161	16,166,194	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Book/Tax Acc Depr Difference		(2,417,992)	(5,671,340)	(7,740,227)	(8,963,071)	(9,583,533)	(10,202,302)	(10,822,763)	(10,686,862)	(9,796,290)	(8,905,718)	(8,015,147)	(7,124,575)
Deferred ITC		676,835	609,151	541,468	473,784	406,101	338,417	270,734	203,050	135,367	67,683	-	-
Net Deferred Tax Asset (Liability)		(448,381)	(1,303,609)	(1,853,816)	(2,186,151)	(2,363,361)	(2,540,136)	(2,717,346)	(2,699,779)	(2,487,869)	(2,275,960)	(2,064,051)	(1,834,712)
Deferred Tax Base		1,741,157	3,321,031	2,136,571	1,290,528	688,145	686,453	688,145	(68,218)	(822,888)	(822,888)	(822,888)	(890,572)
Deferred Taxes - Federal		343,649	655,467	421,692	254,709	135,818	135,484	135,818	(13,464)	(162,412)	(162,412)	(162,412)	(175,771)
Deferred Taxes - State excluding credit		104,731	199,761	128,516	77,626	41,392	41,290	41,392	(4,103)	(49,497)	(49,497)	(49,497)	(53,568)
Change in Deferred Taxes		448,381	855,228	550,207	332,335	177,210	176,774	177,210	(17,567)	(211,909)	(211,909)	(211,909)	(229,339)
Accumulated Deferred Taxes		448,381	1,303,609	1,853,816	2,186,151	2,363,361	2,540,136	2,717,346	2,699,779	2,487,869	2,275,960	2,064,051	1,834,712
check		-	-	-	-	-	-	-	-	-	-	-	-
Change in Deferred ITC		676,835	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	-
		676,835	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	-
Rate Base and Financing													
Investment: (Rate Base)													
Gross Plant		16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Accumulated Depreciation		-	890,572	1,781,144	2,671,716	3,562,287	4,452,859	5,343,431	6,234,003	7,124,575	8,015,147	8,905,718	9,796,290
Accumulated Deferred Taxes		448,381	1,303,609	1,853,816	2,186,151	2,363,361	2,540,136	2,717,346	2,699,779	2,487,869	2,275,960	2,064,051	1,834,712
Accumulated Deferred ITC		676,835	609,151	541,468	473,784	406,101	338,417	270,734	203,050	135,367	67,683	-	-
Ending Net Investment	-	15,795,650	14,117,533	12,744,438	11,589,214	10,589,116	9,589,453	8,589,354	7,784,033	7,173,054	6,562,075	5,951,096	5,289,863
Average Net Investment		7,897,825	14,956,592	13,430,986	12,166,826	11,089,165	10,089,284	9,089,403	8,186,694	7,478,544	6,867,564	6,256,585	5,620,479

Confidential Information Deleted
Pursuant to Protective Order No. ______

Revenue Requirements Model - Calculations													
Manual input		1	2	3	4	5	6	7	8	9	10	11	12
Average Financing:													
Short Term Debt	0.61%	48,050	90,995	81,713	74,022	67,466	61,383	55,299	49,807	45,499	41,782	38,065	34,195
Long Term Debt (Revenue Bonds)	40.59%	3,206,000	6,071,397	5,452,101	4,938,935	4,501,475	4,095,589	3,689,703	3,323,262	3,035,799	2,787,781	2,539,764	2,281,547
Taxable Debt	0.80%	63,101	119,499	107,310	97,209	88,599	80,610	72,622	65,409	59,751	54,870	49,988	44,906
Preferred Stock	1.17%	92,310	174,812	156,981	142,206	129,610	117,923	106,237	95,686	87,409	80,268	73,127	65,692
Common Equity	56.83%	4,488,364	8,499,888	7,632,881	6,914,454	6,302,015	5,733,779	5,165,543	4,652,529	4,250,085	3,902,863	3,555,641	3,194,140
Total Financing		7,897,825	14,956,592	13,430,986	12,166,826	11,089,165	10,089,284	9,089,403	8,186,694	7,478,544	6,867,564	6,256,585	5,620,479
Return on Investment													
Short Term Debt	3.75%	1,802	3,412	3,064	2,776	2,530	2,302	2,074	1,868	1,706	1,567	1,427	1,282
Long Term Debt (Taxable Debt)	4.79%	153,567	290,820	261,156	236,575	215,621	196,179	176,737	159,184	145,415	133,535	121,655	109,286
Hybrids	7.83%	4,941	9,357	8,402	7,612	6,937	6,312	5,686	5,122	4,679	4,296	3,914	3,516
Total Interest Expense		160,310	303,589	272,622	246,962	225,088	204,792	184,497	166,174	151,800	139,398	126,996	114,085
Preferred Dividends	8.12%	7,496	14,195	12,747	11,547	10,524	9,575	8,626	7,770	7,098	6,518	5,938	5,334
Net Income on Common	9.50%	426,395	807,489	725,124	656,873	598,691	544,709	490,727	441,990	403,758	370,772	337,786	303,443
Income Taxes													
Income Before Pref Dividends		433,890	821,684	737,871	668,420	609,216	554,284	499,353	449,760	410,856	377,290	343,724	308,777
Income Before Taxes (including ITC)		584,379	1,106,673	993,790	900,252	820,513	746,530	672,546	605,753	553,355	508,147	462,939	415,872
Investment Tax Credit		-	67,683	67,683	67,683	67,683	67,683	67,683	67,683	67,683	67,683	67,683	-
Income Before Taxes (excluding ITC)		584,379	1,038,990	926,107	832,569	752,830	678,846	604,863	538,069	485,672	440,464	395,256	415,872
Federal Income Tax		115,338	218,422	196,143	177,681	161,943	147,341	132,739	119,556	109,215	100,292	91,370	82,080
State Income Tax		35,151	66,567	59,777	54,150	49,354	44,904	40,454	36,436	33,285	30,565	27,846	25,015
State Investment Tax Credit		-	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	-
Total State Tax		35,151	(1,117)	(7,907)	(13,533)	(18,329)	(22,779)	(27,230)	(31,247)	(34,399)	(37,118)	(39,837)	25,015
Total Taxes		150,488	217,306	188,236	164,148	143,614	124,562	105,510	88,309	74,816	63,174	51,532	107,095
Revenue Requirement Calculation													
Revenue Requirement Factors		[redacted]											
Revenue Requirement													
Revenue Taxes													
Income Before Depr, Int, Inc Tax		744,689	2,233,151	2,089,301	1,970,103	1,868,490	1,774,211	1,679,931	1,594,815	1,528,043	1,470,433	1,412,824	1,420,529
Depreciation Expense		-	890,572	890,572	890,572	890,572	890,572	890,572	890,572	890,572	890,572	890,572	890,572
O&M		-	-	-	-	-	-	-	-	-	-	-	-
Interest Expense		160,310	303,589	272,622	246,962	225,088	204,792	184,497	166,174	151,800	139,398	126,996	114,085
Income Before Income Taxes		584,379	1,038,990	926,107	832,569	752,830	678,846	604,863	538,069	485,672	440,464	395,256	415,872
Income Taxes - Federal		115,338	218,422	196,143	177,681	161,943	147,341	132,739	119,556	109,215	100,292	91,370	82,080
Income Taxes - State		35,151	66,567	59,777	54,150	49,354	44,904	40,454	36,436	33,285	30,565	27,846	25,015
State ITC		-	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	(67,683)	-
Total Income Taxes		150,488	217,306	188,236	164,148	143,614	124,562	105,510	88,309	74,816	63,174	51,532	107,095
Preferred Dividends		7,496	14,195	12,747	11,547	10,524	9,575	8,626	7,770	7,098	6,518	5,938	5,334
Net Income for Common	[redacted]												
	check	-	-	-	-	-	-	-	-	-	-	-	-
	ROE	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%

EXHIBIT 5
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Keahole Self Build Battery Energy Storag
Revenue Requirements Model - Calculati

	13	14	15	16	17	18	19	20	21	22	23	24
Manual input	13	14	15	16	17	18	19	20	21	22	23	24
O&M												
Escalation Rate	1.22	1.24	1.27	1.29	1.32	1.35	1.37	1.40	1.43	1.46	1.49	1.52
O&M	-	-	-	-	-	-	-	-	-	-	-	-
Plant Asset Depreciation												
Book Depreciation												
Book Depreciation Rates	5.263%	5.263%	5.263%	5.263%	5.263%	5.263%	5.263%	5.263%	0.000%	0.000%	0.000%	0.000%
Depreciation Expense	890,572	890,572	890,572	890,572	890,572	890,572	890,572	890,572	-	-	-	-
Accumulated Depreciation	10,686,862	11,577,434	12,468,006	13,358,578	14,249,149	15,139,721	16,030,293	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Tax Depreciation												
Tax Depreciation Rates (Straight Line)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Tax Basis (S/L)	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation Rates (MACRS)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
NonRB Financed Tax Basis (MACRS)	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Tax Depreciation	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
State Investment Tax Credit (ITC)												
Book												
State ITC Amortization Rate	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Amortization of State ITC	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Amortization	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835
Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
Tax												
Deferred Tax Calculation												
Book Accumulated Depreciation	10,686,862	11,577,434	12,468,006	13,358,578	14,249,149	15,139,721	16,030,293	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Tax Accumulated Depreciation	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Book/Tax Acc Depr Difference	(6,234,003)	(5,343,431)	(4,452,859)	(3,562,287)	(2,671,716)	(1,781,144)	(890,572)	-	-	-	-	-
Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
Net Deferred Tax Asset (Liability)	(1,605,373)	(1,376,034)	(1,146,695)	(917,356)	(688,017)	(458,678)	(229,339)	-	-	-	-	-
Deferred Tax Base	(890,572)	(890,572)	(890,572)	(890,572)	(890,572)	(890,572)	(890,572)	(890,572)	-	-	-	-
Deferred Taxes - Federal	(175,771)	(175,771)	(175,771)	(175,771)	(175,771)	(175,771)	(175,771)	(175,771)	-	-	-	-
Deferred Taxes - State excluding credit	(53,568)	(53,568)	(53,568)	(53,568)	(53,568)	(53,568)	(53,568)	(53,568)	-	-	-	-
Change in Deferred Taxes	(229,339)	(229,339)	(229,339)	(229,339)	(229,339)	(229,339)	(229,339)	(229,339)	-	-	-	-
Accumulated Deferred Taxes	1,605,373	1,376,034	1,146,695	917,356	688,017	458,678	229,339	0	0	0	0	0
check	-	-	-	0	0	0	0	0	0	0	0	0
Change in Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-
Rate Base and Financing												
Investment: (Rate Base)												
Gross Plant	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Accumulated Depreciation	10,686,862	11,577,434	12,468,006	13,358,578	14,249,149	15,139,721	16,030,293	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Accumulated Deferred Taxes	1,605,373	1,376,034	1,146,695	917,356	688,017	458,678	229,339	0	0	0	0	0
Accumulated Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
Ending Net Investment	4,628,630	3,967,397	3,306,164	2,644,931	1,983,699	1,322,466	661,233	(0)	(0)	(0)	(0)	(0)
Average Net Investment	4,959,246	4,298,014	3,636,781	2,975,548	2,314,315	1,653,082	991,849	330,616	(0)	(0)	(0)	(0)

Revenue Requirements Model - Calculati												
Manual input	13	14	15	16	17	18	19	20	21	22	23	24
Average Financing:												
Short Term Debt	30,172	26,149	22,126	18,103	14,080	10,057	6,034	2,011	(0)	(0)	(0)	(0)
Long Term Debt (Revenue Bonds)	2,013,129	1,744,712	1,476,295	1,207,878	939,460	671,043	402,626	134,209	(0)	(0)	(0)	(0)
Taxable Debt	39,623	34,340	29,057	23,774	18,491	13,208	7,925	2,642	(0)	(0)	(0)	(0)
Preferred Stock	57,964	50,235	42,507	34,778	27,050	19,321	11,593	3,864	(0)	(0)	(0)	(0)
Common Equity	2,818,359	2,442,578	2,066,796	1,691,015	1,315,234	939,453	563,672	187,891	(0)	(0)	(0)	(0)
Total Financing	4,959,246	4,298,014	3,636,781	2,975,548	2,314,315	1,653,082	991,849	330,616	(0)	(0)	(0)	(0)
Return on Investment												
Short Term Debt	1,131	981	830	679	528	377	226	75	(0)	(0)	(0)	(0)
Long Term Debt (Taxable Debt)	96,429	83,572	70,715	57,857	45,000	32,143	19,286	6,429	(0)	(0)	(0)	(0)
Hybrids	3,102	2,689	2,275	1,861	1,448	1,034	620	207	(0)	(0)	(0)	(0)
Total Interest Expense	100,663	87,241	73,819	60,398	46,976	33,554	20,133	6,711	(0)	(0)	(0)	(0)
Preferred Dividends	4,707	4,079	3,452	2,824	2,196	1,569	941	314	(0)	(0)	(0)	(0)
Net Income on Common	267,744	232,045	196,346	160,646	124,947	89,248	53,549	17,850	(0)	(0)	(0)	(0)
Income Taxes												
Income Before Pref Dividends	272,451	236,124	199,797	163,470	127,144	90,817	54,490	18,163	(0)	(0)	(0)	(0)
Income Before Taxes (including ITC)	366,946	318,020	269,094	220,168	171,242	122,315	73,389	24,463	(0)	(0)	(0)	(0)
Investment Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-
Income Before Taxes (excluding ITC)	366,946	318,020	269,094	220,168	171,242	122,315	73,389	24,463	(0)	(0)	(0)	(0)
Federal Income Tax	72,424	62,767	53,111	43,454	33,798	24,141	14,485	4,828	(0)	(0)	(0)	(0)
State Income Tax	22,072	19,129	16,186	13,243	10,300	7,357	4,414	1,471	(0)	(0)	(0)	(0)
State Investment Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-
Total State Tax	22,072	19,129	16,186	13,243	10,300	7,357	4,414	1,471	(0)	(0)	(0)	(0)
Total Taxes	94,496	81,896	69,297	56,697	44,098	31,499	18,899	6,300	(0)	(0)	(0)	(0)
Revenue Requirement Calculation												
Revenue Requirement Factors	[redacted]								**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**
Revenue Requirement									**(0)**	**(0)**	**(0)**	**(0)**
Revenue Taxes									(0)	(0)	(0)	(0)
Income Before Depr, Int, Inc Tax	1,358,181	1,295,833	1,233,485	1,171,137	1,108,789	1,046,442	984,094	921,746	(0)	(0)	(0)	(0)
Depreciation Expense	890,572	890,572	890,572	890,572	890,572	890,572	890,572	890,572	-	-	-	-
O&M	-	-	-	-	-	-	-	-	-	-	-	-
Interest Expense	100,663	87,241	73,819	60,398	46,976	33,554	20,133	6,711	(0)	(0)	(0)	(0)
Income Before Income Taxes	366,946	318,020	269,094	220,168	171,242	122,315	73,389	24,463	(0)	(0)	(0)	(0)
Income Taxes - Federal	72,424	62,767	53,111	43,454	33,798	24,141	14,485	4,828	(0)	(0)	(0)	(0)
Income Taxes - State	22,072	19,129	16,186	13,243	10,300	7,357	4,414	1,471	(0)	(0)	(0)	(0)
State ITC	-	-	-	-	-	-	-	-	-	-	-	-
Total Income Taxes	94,496	81,896	69,297	56,697	44,098	31,499	18,899	6,300	(0)	(0)	(0)	(0)
Preferred Dividends	4,707	4,079	3,452	2,824	2,196	1,569	941	314	(0)	(0)	(0)	(0)
Net Income for Common	[redacted]								(0)	(0)	(0)	(0)
	-	(0)	-	-	(0)	-	(0)	(0)	-	-	-	-
	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%

Keahole Self Build Battery Energy Storag												
Revenue Requirements Model - Calculati												
Manual input	25	26	27	28	29	30	31	32	33	34	35	36
O&M												
Escalation Rate	1.55	1.58	1.61	1.64	1.67	1.71	1.74	1.78	1.81	1.85	1.88	1.92
O&M	-	-	-	-	-	-	-	-	-	-	-	-
Plant Asset Depreciation												
Book Depreciation												
Book Depreciation Rates	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Depreciation	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Tax Depreciation												
Tax Depreciation Rates (Straight Line)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Tax Basis (S/L)	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation Rates (MACRS)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
NonRB Financed Tax Basis (MACRS)	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Tax Depreciation	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
State Investment Tax Credit (ITC)												
Book												
State ITC Amortization Rate	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Amortization of State ITC	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Amortization	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835
Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
Tax												
Deferred Tax Calculation												
Book Accumulated Depreciation	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Tax Accumulated Depreciation	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Book/Tax Acc Depr Difference	-	-	-	-	-	-	-	-	-	-	-	-
Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
Net Deferred Tax Asset (Liability)	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Tax Base	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes - Federal	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes - State excluding credit	-	-	-	-	-	-	-	-	-	-	-	-
Change in Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0
check	0	0	0	0	0	0	0	0	0	0	0	0
Change in Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-
Rate Base and Financing												
Investment: (Rate Base)												
Gross Plant	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Accumulated Depreciation	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Accumulated Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0
Accumulated Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
Ending Net Investment	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Average Net Investment	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)

Revenue Requirements Model - Calculati												
Manual input	25	26	27	28	29	30	31	32	33	34	35	36
Average Financing:												
Short Term Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Long Term Debt (Revenue Bonds)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Taxable Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Preferred Stock	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Common Equity	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Financing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Return on Investment												
Short Term Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Long Term Debt (Taxable Debt)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Hybrids	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Interest Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Preferred Dividends	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net Income on Common	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Taxes												
Income Before Pref Dividends	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Before Taxes (including ITC)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Investment Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-
Income Before Taxes (excluding ITC)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Federal Income Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
State Income Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
State Investment Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-
Total State Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Revenue Requirement Calculation												
Revenue Requirement Factors	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**
Revenue Requirement	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**
Revenue Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Before Depr, Int, Inc Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	-	-	-	-	-	-	-	-
Interest Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Before Income Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Taxes - Federal	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Taxes - State	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
State ITC	-	-	-	-	-	-	-	-	-	-	-	-
Total Income Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Preferred Dividends	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net Income for Common	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	-	-	-	-	-	-	-	-	-	-	-	-
	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%

Keahole Self Build Battery Energy Storag												
Revenue Requirements Model - Calculati												
Manual input	37	38	39	40	41	42	43	44	45	46	47	48
O&M												
Escalation Rate	1.96	2.00	2.04	2.08	2.12	2.16	2.21	2.25	2.30	2.34	2.39	2.44
O&M	-	-	-	-	-	-	-	-	-	-	-	-
Plant Asset Depreciation												
Book Depreciation												
Book Depreciation Rates	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Depreciation	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Tax Depreciation												
Tax Depreciation Rates (Straight Line)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Tax Basis (S/L)	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation Rates (MACRS)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
NonRB Financed Tax Basis (MACRS)	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Tax Depreciation	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
State Investment Tax Credit (ITC)												
Book												
State ITC Amortization Rate	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Amortization of State ITC	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Amortization	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835
Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
Tax												
Deferred Tax Calculation												
Book Accumulated Depreciation	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Tax Accumulated Depreciation	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Book/Tax Acc Depr Difference	-	-	-	-	-	-	-	-	-	-	-	-
Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
Net Deferred Tax Asset (Liability)	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Tax Base	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes - Federal	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes - State excluding credit	-	-	-	-	-	-	-	-	-	-	-	-
Change in Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0
check	0	0	0	0	0	0	0	0	0	0	0	0
Change in Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-
Rate Base and Financing												
Investment: (Rate Base)												
Gross Plant	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Accumulated Depreciation	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Accumulated Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0
Accumulated Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
Ending Net Investment	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Average Net Investment	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)

Revenue Requirements Model - Calculati												
Manual input	37	38	39	40	41	42	43	44	45	46	47	48
Average Financing:												
Short Term Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Long Term Debt (Revenue Bonds)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Taxable Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Preferred Stock	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Common Equity	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Financing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Return on Investment												
Short Term Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Long Term Debt (Taxable Debt)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Hybrids	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Interest Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Preferred Dividends	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net Income on Common	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Taxes												
Income Before Pref Dividends	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Before Taxes (including ITC)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Investment Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-
Income Before Taxes (excluding ITC)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Federal Income Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
State Income Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
State Investment Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-
Total State Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Revenue Requirement Calculation												
Revenue Requirement Factors	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**
Revenue Requirement	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**
Revenue Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Before Depr, Int, Inc Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	-	-	-	-	-	-	-	-
Interest Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Before Income Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Taxes - Federal	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Taxes - State	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
State ITC	-	-	-	-	-	-	-	-	-	-	-	-
Total Income Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Preferred Dividends	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net Income for Common	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	-	-	-	-	-	-	-	-	-	-	-	-
	9.5%	*9.5%*	*9.5%*	*9.5%*	*9.5%*	*9.5%*	*9.5%*	*9.5%*	*9.5%*	*9.5%*	*9.5%*	*9.5%*

Keahole Self Build Battery Energy Storag												
Revenue Requirements Model - Calculati												
Manual input	49	50	51	52	53	54	55	56	57	58	59	60
O&M												
Escalation Rate	2.49	2.54	2.59	2.64	2.69	2.75	2.80	2.86	2.91	2.97	3.03	3.09
O&M	-	-	-	-	-	-	-	-	-	-	-	-
Plant Asset Depreciation												
Book Depreciation												
Book Depreciation Rates	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Depreciation	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Tax Depreciation												
Tax Depreciation Rates (Straight Line)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Tax Basis (S/L)	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation Rates (MACRS)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
NonRB Financed Tax Basis (MACRS)	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Tax Depreciation	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
State Investment Tax Credit (ITC)												
Book												
State ITC Amortization Rate	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Amortization of State ITC	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Amortization	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835	676,835
Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
Tax												
Deferred Tax Calculation												
Book Accumulated Depreciation	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Tax Accumulated Depreciation	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Book/Tax Acc Depr Difference	-	-	-	-	-	-	-	-	-	-	-	-
Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
Net Deferred Tax Asset (Liability)	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Tax Base	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes - Federal	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes - State excluding credit	-	-	-	-	-	-	-	-	-	-	-	-
Change in Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0
check	0	0	0	0	0	0	0	0	0	0	0	0
Change in Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-
Rate Base and Financing												
Investment: (Rate Base)												
Gross Plant	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Accumulated Depreciation	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865	16,920,865
Accumulated Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0
Accumulated Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
Ending Net Investment	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Average Net Investment	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)

Revenue Requirements Model - Calculati												
Manual input	49	50	51	52	53	54	55	56	57	58	59	60
Average Financing:												
Short Term Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Long Term Debt (Revenue Bonds)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Taxable Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Preferred Stock	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Common Equity	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Financing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Return on Investment												
Short Term Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Long Term Debt (Taxable Debt)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Hybrids	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Interest Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Preferred Dividends	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net Income on Common	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Taxes												
Income Before Pref Dividends	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Before Taxes (including ITC)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Investment Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-
Income Before Taxes (excluding ITC)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Federal Income Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
State Income Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
State Investment Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-
Total State Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Revenue Requirement Calculation												
Revenue Requirement Factors	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**	**(0.0000)**
Revenue Requirement	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**
Revenue Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Before Depr, Int, Inc Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	-	-	-	-	-	-	-	-
Interest Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Before Income Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Taxes - Federal	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Taxes - State	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
State ITC	-	-	-	-	-	-	-	-	-	-	-	-
Total Income Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Preferred Dividends	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net Income for Common	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	-	-	-	-	-	-	-	-	-	-	-	-
	9.5%	*9.5%*	*9.5%*	*9.5%*	*9.5%*	*9.5%*	*9.5%*	*9.5%*	*9.5%*	*9.5%*	*9.5%*	*9.5%*

Keahole Self Build Battery Energy Storag	
Revenue Requirements Model - Calculati	
Manual input	Total
O&M	
Escalation Rate	
O&M	-
Plant Asset Depreciation	
Book Depreciation	
Book Depreciation Rates	100.00%
Depreciation Expense	16,920,865
Accumulated Depreciation	
Tax Depreciation	
Tax Depreciation Rates (Straight Line)	100.00%
Tax Basis (S/L)	-
Tax Depreciation Rates (MACRS)	100.00%
NonRB Financed Tax Basis (MACRS)	16,920,865
Tax Depreciation	16,920,865
Accumulated Tax Depreciation	
State Investment Tax Credit (ITC)	
Book	
State ITC Amortization Rate	100.00%
Amortization of State ITC	676,835
Accumulated Amortization	
Deferred ITC	
Tax	
Deferred Tax Calculation	
Book Accumulated Depreciation	
Tax Accumulated Depreciation	
Book/Tax Acc Depr Difference	
Deferred ITC	
Net Deferred Tax Asset (Liability)	
Deferred Tax Base	
Deferred Taxes - Federal	
Deferred Taxes - State excluding credit	
Change in Deferred Taxes	
Accumulated Deferred Taxes	
check	
Change in Deferred ITC	
Rate Base and Financing	
Investment: (Rate Base)	
Gross Plant	
Accumulated Depreciation	
Accumulated Deferred Taxes	
Accumulated Deferred ITC	
Ending Net Investment	
Average Net Investment	

EXHIBIT 5
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Revenue Requirements Model - Calculati		
	Manual input	Total
	Average Financing:	
	Short Term Debt	
	Long Term Debt (Revenue Bonds)	
	Taxable Debt	
	Preferred Stock	
	Common Equity	
	Total Financing	
Return on Investment		
	Short Term Debt	
	Long Term Debt (Taxable Debt)	
	Hybrids	
	Total Interest Expense	
	Preferred Dividends	
	Net Income on Common	
Income Taxes		
	Income Before Pref Dividends	
	Income Before Taxes (including ITC)	
	Investment Tax Credit	
	Income Before Taxes (excluding ITC)	
	Federal Income Tax	
	State Income Tax	
	State Investment Tax Credit	
	Total State Tax	
	Total Taxes	
Revenue Requirement Calculation		
	Revenue Requirement Factors	
	Revenue Requirement	
	Revenue Taxes	
	Income Before Depr, Int, Inc Tax	
	Depreciation Expense	
	O&M	
	Interest Expense	
	Income Before Income Taxes	
	Income Taxes - Federal	
	Income Taxes - State	
	State ITC	
	Total Income Taxes	
	Preferred Dividends	
	Net Income for Common	

EXHIBIT 5
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Hawaii Electric Light
IGP 2020 Sales Forecast (MWh)

	Sch R	Sch G/J	Sch P	Sch F	Total Sales
2020	401,814	372,486	270,965	2,489	1,047,754
2021	390,605	364,488	268,617	2,480	1,026,189
2022	384,614	359,297	268,772	2,484	1,015,166
2023	380,346	355,031	269,857	2,487	1,007,722
2024	379,129	352,159	269,822	2,504	1,003,614
2025	375,457	349,271	268,802	2,495	996,024
2026	372,373	345,969	268,346	2,499	989,187
2027	369,083	342,991	267,668	2,503	982,246
2028	370,916	341,683	267,855	2,520	982,973
2029	370,548	338,706	266,454	2,511	978,219
2030	372,266	336,742	265,969	2,514	977,491
2031	375,069	334,707	265,400	2,518	977,693
2032	378,396	333,801	265,526	2,535	980,258
2033	380,350	331,293	264,161	2,526	978,330
2034	384,923	330,057	263,689	2,530	981,199
2035	390,898	332,110	263,454	2,534	988,996
2036	399,742	332,677	264,069	2,551	999,038
2037	407,191	332,053	263,367	2,541	1,005,152
2038	415,033	332,363	263,557	2,545	1,013,498
2039	424,546	332,851	263,694	2,549	1,023,641
2040	436,155	334,821	264,811	2,566	1,038,353
2041	445,965	334,642	264,523	2,557	1,047,686
2042	459,577	335,959	264,983	2,561	1,063,080
2043	475,172	337,712	265,708	2,564	1,081,157
2044	491,442	340,817	267,063	2,581	1,101,904
2045	507,892	342,539	267,095	2,572	1,120,098
2046	526,116	345,109	268,019	2,576	1,141,820
2047	546,400	348,456	268,914	2,580	1,166,350
2048	567,559	352,832	270,838	2,597	1,193,827
2049	586,890	355,720	271,120	2,587	1,216,317
2050	609,026	359,700	272,436	2,591	1,243,754

Keahole Self Build Battery Energy Storage System (BESS) Rev Req and Bill Impact
Capital Costs

[redacted]

[redacted]	16,920,865

From "Final Keahole O_M Cost Proposal UPDATED.xlsx
Note: All numbers are hardcoded below.

Costs by Year

No	Year	Annual Cost (2020 Dollars)	4 year periodic costs (2020 Dollars)	5 year periodic costs (2020 Dollars)	Total Costs (2020 Dollars)	Total Costs (2% Escalation)	CMA (No Escalation)	Annual Ins. Prem (2% Esc)	Total O&M Costs by Year	
1	2022	[redacted]								
2	2023									
3	2024									
4	2025									
5	2026									
6	2027									
7	2028									
8	2029									
9	2030									
10	2031									
11	2032									
12	2033									
13	2034									
14	2035									
15	2036									
16	2037									
17	2038									
18	2039									
19	2040									
20	2041									
									[redacted]	Total

Exhibit 6 - Contingency Energy Storage Update Study

As ordered by the Commission[1], the Company evaluated the Hawai'i Island grid to determine whether 18MW of Fast Frequency Response ("FFR") capacity was still needed to meet planning criteria, with the planned Stage 1 RFP projects ability to contribute primary frequency response. The Company also evaluated the high-level frequency response contributions of the Stage 2 final award group during the detailed evaluation. As described below the Company determined that the 18 MW of FFR is the appropriate amount of FFR to procure to assure system security for a range of system disturbances.

In April 2019, the Company updated a 2015 study to size the amount of Fast Frequency Response ("FFR") needed for certain loss of generation scenarios. The Hawaii Island transmission planning criteria allows up to 15% of load to be shed for the loss of a single generator. The study was updated to reflect changes that were implemented in the underfrequency load shed ("UFLS") scheme and to reflect the latest information on the amounts of legacy PV that trip at certain voltages and frequencies. The new UFLS scheme changed from a static scheme to an adaptive and dynamic scheme that actively ensures the first two load shed blocks in the scheme are equivalent to 15% of net load.

For the purposes of this study, the objective was for the contingency FFR to ensure that the historical reliability during contingency events was maintained: the historical and current planning criteria states that for single contingency events, no more than 15% of the net load should be shed.

For a range of various daytime cases with net system load at 82 MW, a modeled trip of the Keāhole single train combined cycle unit with an output of 24.5 MW or Hamakua Energy Partners ("HEP") Plant running as a single train combined cycle unit with an output of 27 to 28 MW resulted in 4 blocks of load shed or 40% of total load. This exceeded the 15% underfrequency load shed criteria. This case was used as the basis to determine the amount of FFR required to meet the reliability objective of no more than 15% UFLS for single contingency.

When rerunning the same scenarios but with a 12 MW FFR resource, the same size generator trip of Keāhole or HEP results in three blocks of load shed or 25% of total load. In some scenarios it resulted in three blocks of load shed plus an added kicker block to stabilize the frequency back to 60 Hz.

With the structure of the Stage 2 and Grid Services procurement, which sought increments of 6 MW of FFR, the study also analyzed a case with an 18 MW FFR resource. For the range of scenarios studied, the trip of Keāhole or HEP resulted in either two blocks of load shed, or zero

[1] See. Docket No. 2017-0352, Order No. 36474, at page 31 – 32.

blocks of load shed, leading to the conclusion that 18 MW of FFR was the appropriate size for an FFR resource.

An additional consideration of FFR was the potential to prevent system failure for secondary fault clearing and breaker failure scenarios. The 18 MW FFR contingency response did not eliminate but did mitigate the risk to some extent for these types of possible, but lower probability contingencies. In conjunction with the storage addition, the company is gradually upgrading the system communications, protection, and substation design to potentially reduce the extended clearing times that create the severe disturbances.

Stage 1 Interconnection Requirements Study

Although the purpose of the Stage 1 Interconnection Requirements Study ("IRS") is intended to test the impact of the addition of the Stage 1 projects to the system, and not to specifically determine the amount of FFR that is required to meet the planning criteria, the study offers an additional data point when considering the FFR needs on the system. Notably the IRS considers the system with the addition of the Stage 1 projects and the services they may provide.

In the daytime minimum cases (indicated as dm_1 or dm_2, in Table 1) the Puna Geothermal Venture ("PGV") plant is dispatched. HEP is dispatched as a single train combined cycle plant in the dm_1 case and Hill 5 generator is dispatched in the dm_2 case. All other synchronous generators are offline. The remaining load is served by both the Waikoloa Solar and Hale Kuawehi solar and battery energy storage system ("BESS") plant with an output of 30 MW for each plant. Rooftop solar is also included in the dispatch.

Table 1 from the IRS demonstrates that for these dispatches in which both Stage 1 projects are exporting to the grid, three blocks of load are shed for the largest loss of generation, which violates the 15% load shed planning criteria. In this case, because the dispatch is maximizing the renewable Stage 1 resources and minimizing the amount of fossil fuel units that are online, there is limited upward reserve and inertia to compensate for the loss of a 30 MW PV plant.

Table 1. Generator Contingencies with UFLS Above Stage 2 (i.e., more than 15 % load shed) With no FFR

Cont. #	Study Case	Unit Tripped	Total Load MW Tripped/ Shed	Total Load MVar Tripped/ Shed	UFLS Tripping stage
3	dm_1_proj_1	AES_WAI	33.94	8.72	3
6	dm_1_proj_1_and_2	AES_WAI	33.94	8.72	3
7	dm_1_proj_1_and_2	INGX_PRKR	33.94	8.72	3
10	dm_1_proj_2	INGX_PRKR	33.94	8.72	3
13	dm_2_proj_1	AES_WAI	33.94	8.72	3
16	dm_2_proj_1_and_2	AES_WAI	65.15	17.68	4
17	dm_2_proj_1_and_2	INGX_PRKR	72.67	18.45	5
20	dm_2_proj_2	INGX_PRKR	33.94	8.72	3
33	em_proj_1	AES_WAI	26	6.06	3
40	em_proj_2	INGX_PRKR	26	6.06	3

The IRS found that installing a standalone 25 MW BESS is one possible mitigation to bring the system back into compliance with the planning criteria. The study tested various sizes but found that 25 MW was approximately the minimum amount that would limit load shedding to two blocks or 15% of load. The size of the standalone BESS found here is larger than that of the Contingency Energy Storage Update Study because the IRS assumed a 5% droop response whereas the Contingency Energy Storage Update study assumed 1% droop response. The typical design of the FFR (in the Contingency Energy Storage Update Study) is such that it will not deploy during non-disturbance events but is designed to deploy or absorb energy during frequency excursions beyond the bandwidth of normal conditions, proportional to the system needs and with a very fast response. This is an important factor because a large portion of installed DER will trip at 60.5 Hz or more. This contingency size exceeds the present single largest contingency of 30 MW. With the FFR responding to resist the over-frequency, a substantial loss of legacy DER can be avoided. Loss of all DER is an event that can risk the system during high PV production hours.

With a 5% droop response, the frequency would need to drop to 57Hz in order to utilize the full 25MW response capability. Therefore, with the performance parameters of an FFR resource, 18 MW of FFR is expected to be sufficient depending on the response of the resource and the rate of change of frequency, along with the primary frequency response of future resources.

Additional Benchmark Cases

Following the Interconnection Requirements Study, the Company ran benchmarking cases to assess the state of the system after installation of the Stage 1 projects. The notable case included a dispatch where the only synchronous generator online was PGV, dispatched at 22 MW. Three of the existing combustion turbine units (Keāhole CT4, CT5, and Puna CT3) were assumed to be converted to synchronous condensers to provide voltage, inertia, and short circuit current services for system security. The dispatch is listed in Table 2.

Table 2. Benchmark Cases Dispatch

	Unit		Unit Ratings					Post Stage 1 Dispatch		
			Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Synchronous Units	PGV		38.0	22.0	2.94	59.4	174	22.0	16.0	0.0
	Hill 5		13.7	4.0	2.20	15.6	34			
	Hill 6		20.5	8.0	2.53	27.5	70			
	Keāhole STCC		26.0	9.0	3.13	46.5	146			
	Keāhole DTCC		52.0	16.0	2.77	71.8	199			
	HEP STCC		30.0	9.0	1.96	58.9	116			
	HEP DTCC		60.0	20.0	1.78	94.4	168			
	Puna Steam		15.5	6.0	4.63	18.8	87			
	Puna CT3		20.0	7.0	2.23	29.6	66			
	Keāhole CT2		13.8	5.0	3.23	22.2	72			
	Diesels (x9)		2.5	1.5	0.70	3.4	2			
	Puna CT3		0.0	0.0	2.23	29.6	66	0.0	Synch Cond.	
	Keāhole CT4		0.0	0.0	2.10	25.2	53	0.0	Synch Cond.	
	Keāhole CT5		0.0	0.0	2.10	25.2	53	0.0	Synch Cond.	
								Pgen	%CF	
Hydro	HELCO Hydro		4.5	0.0			5	2.1	46%	
	Wailuku Hydro		12.1	0.0	2.42	12.2	30	0.3	2%	
Wind	Apollo		20.5	0.0				15.7	77%	
	HRD		10.5	0.0				0.0	0%	
								Pgen	Net	up reg
Central PV	Waikoloa	PV	30.0	0.0				8.1	8.1	21.9
		ESS	30.0	-30.0				0.0		
	Hale Kuawehi	PV	34.1	0.0				30.0	30.0	0.0
		ESS	30.0	-30.0				0.0		
								Pgen	%CF	
Renewables Subtotal	Hydro		16.6	0				2	14%	-
	Wind		31.0	0				16	51%	-
	Central PV		60.0	0				38	63%	-
	DG-PV		127.7	0				103	80%	
Summary			Total Kinetic Energy						381	
			Total Load						181	

For this case, the state of charge for the Waikoloa BESS was 58%, and the Hale Kuawehi BESS state of charge is 35%. As described in Table 3, for a trip of the Hale Kuawehi plant at 30 MW, the resultant load shed is 21% of load or two blocks plus the kicker block. As a sensitivity, the same trip was re-run with the Waikoloa BESS disabled from responding in the event there is no state of charge available, the BESS is offline on maintenance, or any other circumstance. The result was 40% of load shed or four blocks.

Cases were also run for a trip of Hale Kuawehi, with the Waikoloa plant at various states of charge available to respond to an underfrequency event, and cases in which Waikoloa was unavailable to respond. Both cases are analyzed because at times the storage may be depleted (i.e., nighttime hours or morning hours) due to performing its load shifting function, unable to maintain state of charge because of the limitation on grid charging, unavailable due to maintenance, or other reasons. The FFR resources in these benchmarking cases were all assumed to be located at Keahole Power Plant. The analysis did not include consideration of the impact of some amount of the contingency response provided by resources on the distribution system, some or all of which may be lost through underfrequency load shedding of the first two blocks. However, the analysis below defines the total fast frequency response need whether located at Keahole Power Plant or on the distribution system.

Based on the results in Table 3, when Waikoloa is able to provide a primary frequency droop response, it will reduce the amount of load that would normally be shed for a 30 MW trip of Hale Kuawehi; however, without a separate FFR resource the system fails the planning criteria. In other words, the Stage 1 projects alone cannot satisfy the planning criteria even when a state of charge is available. With the storage capacity primarily being used for load shifting, the state of charge cannot be assumed to be available particularly during the critical PV production hours. The amount of FFR required for the cases studied varied from 12 MW to slightly more than 18 MW contingency FFR to meet the planning criteria. This last result was deemed close enough to meet the criteria.

Table 3. Benchmark Cases with and without FFR resource

Contingency	Gen Unit MW Trip	UFLS Blocks Tripped	Load MW tripped	% Load Tripped	Criteria Pass/Fail	Notes
With ESS PFR response available from Waikoloa						
Hale Kuawehi PV + ESS	30	2 blocks & KB	17.24	21.46%	Fail	No Keahole ESS
Hale Kuawehi PV + ESS	30	1 block & KB	9.08	11.30%	Pass	With 12MW FFR response from Keahole ESS
Hale Kuawehi PV + ESS	30	-	-	-	Pass	With 18MW FFR response from Keahole ESS
No ESS PFR response available from Waikoloa						
Hale Kuawehi PV + ESS	30	4 blocks	32.69	40.68%	Fail	No Keahole ESS
Hale Kuawehi PV + ESS	30	2 blocks & KB	17.24	21.46%	Fail	With 12MW FFR response from Keahole ESS
Hale Kuawehi PV + ESS	30	2 blocks	12.25	15.24%	Pass (borderline)	With 18MW FFR response from Keahole ESS

Based on these benchmarking cases, the Stage 1 projects alone cannot meet the total frequency response needs of the system although, depending on state of charge of the storage, the resources may improve the systems capability to respond to frequency disturbances. To meet the planning criteria a dedicated FFR resource of at least 18 MW is required, which in less severe contingencies will enhance reliability to the Hawaiʻi Island customers over present performance.

Detailed Evaluation of Stage 2 Projects

During the Stage 2 detailed evaluation, the Company performed directional analysis to assess the FFR needs based upon the production simulations associated with the final award group. The directional analysis used algebraic equations to determine the estimated amount of FFR needed for each hour's dispatch in 2024. Production simulations do not cover the entire range of possible dispatches in real time operation but generally represent typical system conditions. In other words, dispatches outside of these typical dispatches can occur but are not covered by this directional analysis and may require additional FFR to avoid violations of the planning criteria.

In reviewing the production simulation data, it was assumed that Stage 1 and Stage 2 battery energy storage systems can provide 4% frequency droop response consistent with the RDG PPA. For every hour, the largest single generator output plus the legacy DG PV output that trips at 59.3 Hz was identified to determine the single largest generator contingency. The following equations were used to determine the hourly FFR need and shortfall.

FFR Requirement = Max Generator Output + legacy PV – Load shed

Where,

- Load shed is the allowable load shed per the planning criteria equivalent to 0.15*net load;
- Legacy PV is calculated at 4% of DGPV online to represent the amount of legacy PV that trips at 59.3 Hz, which would contribute to the maximum generation tripping offline;
- Max Generator Output is the largest generator output at the time of the generator trip

Total PFR Available = PFR avail from Stage 1 and Stage 2 Projects – Tripped PFR

Where,

- PFR available from Stage 1 and Stage 2 projects account for the available headroom of Stage 1 and Stage 2 projects (i.e., rated BESS MW less than current MW output) and a check that there is enough SOC available to respond to a generator trip;
- Tripped PFR, subtracts a specific resource's PFR contribution from the Total PFR available if that resource is identified as the largest generator to be tripped

FFR Shortfall = FFR Requirement – Total PFR Available – SG PFR Available

Where,

- The SG PFR Available is the available PFR contribution of any synchronous generators that may be online at the time

Figure 1: FFR Shortfall by Occurrence

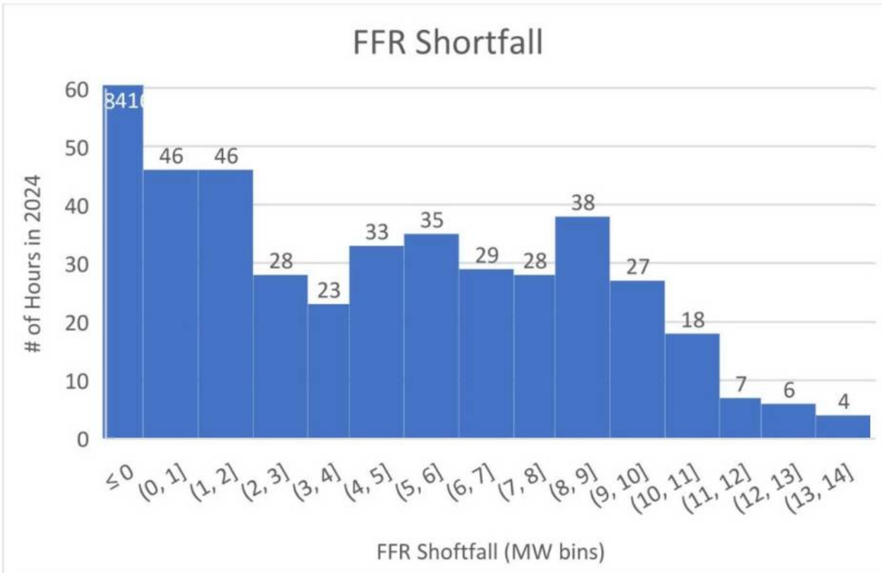
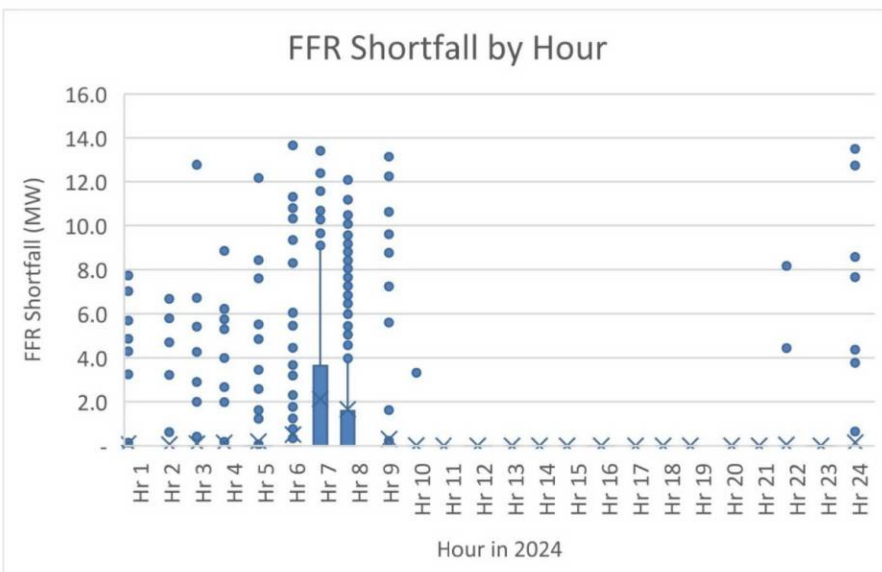


Figure 2: FFR Shortfall by Hour



Based on the 2024 production simulations, Figure 1 shows that up to 14 MW of FFR would be needed after accounting for Stage 1 and Stage 2 resources. Figure 2 shows that many of the hours in 2024 that would require FFR occur when the BESS resources are depleted or have insufficient state of charge to respond to an underfrequency event (i.e., in the morning hours). These findings are consistent with previous analyses discussed above, demonstrating the need for an FFR resource. It is important to note that this analysis was completed without any modeling analysis and should only be used as indicative. Further analysis will be completed as part of the Stage 2 IRS.

<u>18 MW of FFR is the appropriate amount of FFR to procure to assure system security for a range of system disturbances</u>

After accounting for Stage 1 and Stage 2 project contributions to frequency response, 18 MW FFR is still a reasonable amount to acquire for the Hawaii Island system, which includes 6 MW from grid services and 12 MW from standalone energy storage located at Keāhole Power Plant. The FFR service will still be required after Stage 1 projects are installed, and whether or not the selected Stage 2 projects are put into service.

The primary function of the Stage 1 and Stage 2 projects is to provide load shifting to shift the abundance of solar energy to periods of sufficient demand to utilize the energy. Specifically, in reviewing the production simulations for 2024 of the Stage 2 final award portfolio, there are many instances during the evening and morning hours where there are no reserves left in the BESS to provide a frequency response to mitigate the impacts of a generator trip.

Indeed, the RDG PPA allows the Stage 1 and Stage 2 resources to maximize their flexibility and provide frequency response when needed. As demonstrated through the Additional Benchmark cases and the directional analysis of the production simulations, these resources in fact can help to alleviate system security deficiencies for underfrequency load shed events for single generator trips. However, depending on system conditions and dispatch, the Stage 1 or Stage 2 projects may not always be available to respond; especially, given the limitations in the RDG PPA on number of allowable BESS cycles per year to 365 and grid charging capabilities of certain projects.

While it appears that the 2024 production simulations show very few hours where more than 12 MW of FFR would be needed, it must be emphasized that there are other hours of the year where FFR may be required that are not captured by the production simulations since production simulations are based on “typical” conditions rather than boundary cases often experienced on the system. The production simulation model has perfect foresight of variable energy and demand availability. In other words, there may be other hours of the years where insufficient reserves are available to respond to frequency events, and an additional or separate FFR resource would be needed to supplement the response of the Stage 1 and Stage 2 paired projects. Further, the response of the Stage 2 project’s response is highly dependent upon their inverter behavior which will be studied as part of the IRS.

Further, the analysis focuses on single contingencies only. In the planning analysis for procurement, other objectives were considered including n-2, distribution faults, and delayed fault clearing. Without contingency storage, study indicated potential for system failure. The increased size of the FFR contingency storage to 18 MW reduces the severity of such events and, in combination with other efforts being implemented on the system, will reduce potential for system failure for these low frequency, high impact events.

The acceptability of the 12MW Keahole resource assumes 6 MW of FFR will be available through grid services, with equivalent response and impacts as the modeled transmission-connected resource. In the event that the full 18 MW of FFR is not available, some of the more severe contingencies could still result in excessive UFLS.

While a PFR response from Stage 1 and Stage 2 projects may provide some of the total frequency response needed, the FFR BESS also acts as replacement reserves during a loss of generation event by providing up to 30 minutes of continuous supply until other generators can be brought online. As more renewable resources are brought onto the system, online reserves will not be present. Having offline reserves that can be quickly deployed while not having to carry online fossil fuel reserves will benefit the system as well as customers.

In the unlikely event that FFR needs decrease over the course of the lifetime of the 12 MW FFR BESS, the Company could use the BESS to provide other services such as energy shifting, regulation and ramping. Procuring 18 MW total of FFR now will not result in over procurement or underutilization of the resource.

Having a dedicated FFR resource at the Keāhole Power Plant will create a more reliable and resilient grid. The four paired PV and BESS projects from Stage 1 and Stage 2 are located on the same transmission loop in the Waikoloa area. The lack of diversity and robust transmission infrastructure generally makes having 180 MW of PV and BESS in a single area more vulnerable. For context, the typical peak load of the system is 180 MW. Keāhole Power Plant by contrast is in a different location of the system with more robust transmission infrastructure, where five transmission lines emanate from Keāhole Power Plant as opposed to a single transmission loop located in Waikoloa.

Finally, for less impactful contingencies, the FFR will still improve system frequency performance and reduce the amount of load that would otherwise be shed; thereby, reducing the number of customers that would have experienced an outage. The resource will also help mitigate possible system failure for contingencies such as longer fault-clearing, or N-1-1 events. In other cases, it may allow Hawaii Island to survive more severe single generator trips, transmission faults, or contingencies that exceed the loss of a single element, creating a more reliable and resilient Hawaii Island system.

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

Project Justification with Business Case Support for the Keāhole Battery Energy Storage System Project

DATE	PROJECT NAME
8/20/2020	Keāhole Battery Energy Storage System Project ("BESS")
PREPARER/ SUBMITTER	**COMPANY / SPONSOR(S)**
Shelley Takasato	Hawaii Electric Light Company / Robert C. Isler

Note: References to exhibit numbers in this document refer to exhibits included in the accompanying Application.

EXECUTIVE SUMMARY

The Hawaiian Electric Companies issued the Stage 2 Request for Proposals for Variable Renewable Dispatchable Generation and Energy Storage for the Island of Hawai'i (the "Stage 2 RFP")[1] in accordance with Commission Order No. 36474[2] in Docket 2017-0352. The Stage 2 RFP solicited proposals for, among other things, up to 18 megawatts ("MW") of contingency storage, and allowed the Company to submit self-build proposals subject to the requirements of the Stage 2 RFP.

The Keāhole BESS Project was submitted in response to the Stage 2 RFP as a Company self-build proposal. As outlined in the RFP, a robust three phase bid evaluation process, approved by the Commission and overseen by the Independent Observer, evaluated the projects submitted for consideration in response to the Stage 2 RFP, and selected the Keahole BESS to the Final Award Group as providing a necessary amount of contingency storage capability at the best value to customers.

The proposed Keāhole BESS Project is a 12 MW/12 megawatt-hour ("MWh") BESS at Hawai'i Electric Light's Keāhole Generating Station ("Keāhole Generating Station" or "KGS") in Kailua-Kona, Hawai'i. The facility will maintain the required performance and capacities specified in the Stage 2 RFP for a 20-year period. The Project is scheduled to commence construction in June 2021 with an in-service date of December 2022, at a total estimated capital cost of $16.9 million.

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[1] See Docket 2017-0352, *Request for Proposals for Variable Renewable Dispatchable Generation and Energy Storage Island of Hawai'i*, Book 5 of 7, filed August 22, 2019.
[2] See Docket 2017-0352, Order No. 36474, filed August 15, 2019.

Hawai'i Electric Light respectfully submits that the proposed Project is reasonable and in the public interest, and should be approved, as:

- The Project was selected through a Commission-approved competitive procurement process that has resulted in the lowest cost to customers for a required resource;
- The Project incorporates the cost, performance, and financial obligations required of a self-build project as required by the Stage 2 RFP, which are intended to be equivalent to the Energy Storage Power Purchase Agreement contracting mechanism requirements (See Exhibit 1).[3]

BUSINESS CASE

A. Contingency Reserve a Required Resource for Hawai'i Island

Based on earlier planning analyses which are discussed in Exhibit 6 to this Application, the Company proposed including in the Stage 2 RFP a requirement for up to 18 MW of contingency reserve capacity. This contingency reserve was deemed necessary in order to maintain the stability of the Hawai'i Island grid under certain loss of generation scenarios without violating planning criteria for under-frequency load shedding. The Commission approved the Stage 2 RFP with this requirement included, but required that the Company provide a re-analysis of contingency reserve requirements with the planned Stage 1 RFP projects in service.

Exhibit 6 to this Application further clarifies the need for up to 18MW of contingency reserve through a planning analysis of the Hawai'i Island grid, and confirms that using the most current models of the island's renewable and firm resources, the current under-frequency load-shedding scheme, and forecasting the impact of the Stage 1 and Stage 2 RFP projects being placed into service, the requirement for 18MW of contingency reserve capacity remains valid. When all of the planned Stage 1 and Stage 2 RFP projects are in service, Exhibit 6 shows that under certain conditions of loss of generation, 18MW of contingency reserve is needed to avoid violating Hawai'i Island planning criteria for load shedding. Specifically, the Hawai'i Island

[3] See Docket No. 2014-0183, D&O 34696 at 3: "The commission expects the Companies to continuously improve and refine their resource planning tools and methods, and employ these tools to support appropriate competitive procurement processes and Project applications in the near term."

transmission planning criteria allows up to 15% of load shed[4] for the loss of a single generator. Under certain circumstances, the loss of Hamakua Energy Partners or Keāhole Generating Station result in more than 15% of load shed without the required contingency reserve.[5]

B. Keāhole BESS Project Meets Contingency Reserve RFP Requirements

The self-build team developed the Keāhole BESS Project to provide 12MW of the 18MW of contingency reserve capacity requested in the Stage 2 RFP. Technical and performance details were provided in the Company's self-build proposal, including commitments to Project schedule, capacity, and system performance for the 20 year Project life. The Keāhole BESS Project will improve grid reliability and system security by providing Fast Frequency Response 1 ("FFR1") that can be deployed within 12 cycles (200 milliseconds). In addition to the contingency reserve performance requirements, the Keāhole BESS Project meets all of the other specified requirements of the Stage 2 RFP, including the ability to perform energy shifting services, black-start, and grid forming services.

The Company's RFP Team, under the observation of the Independent Observer approved by the Commission, evaluated the Keahole BESS proposal for compliance with the Stage 2 RFP requirements, and determined that the proposed Project satisfied 12MW of the required contingency reserve requirement identified in the Stage 2 RFP, as well as all of the other requirements of the RFP.

C. Keahole BESS is Lowest Cost to Customers

The Stage 2 RFP provided the first test of the full implementation of the Framework for Competitive Bidding, including the participation of the Company self-build team in direct competition with third party providers. A Commission-approved Code of Conduct was implemented, and executed through a set of procedures that was intended to ensure that any Company self-build bids were developed on the same basis as others', and that the resultant bids were evaluated fairly, in an unbiased manner, and provided the required resources at the lowest cost to customers that the market could provide. To ensure that this Code and the supporting procedures were implemented as intended, an Independent Observer was assigned to monitor compliance.

[4] Order no 36356 dated June 20, 2019 p.8

[5] Exhibit 06-Contingency Energy Storage Update Study p. 1

Given that the Stage 2 RFP was executed successfully, and the Keahole BESS was selected to the Final Award Group to provide 12 MW of contingency reserve capacity for the island of Hawai'i, the evaluation process determined that the proposed Project provided the proposed resource at the lowest cost to customers that the market can provide. Specifically:

1. Capital Cost

As detailed in Exhibit 2, the total capital cost upon which the Keāhole BESS Project's successful bid was based is \$16.92 million. This is proposed in the Application as a capped amount, and in the event that actual costs exceed this amount the Company would not be eligible for recovery of any capital cost in excess of \$16.92 million. In the event that actual costs are less than this amount, the Company has proposed a Shared Savings Mechanism through which customers would realize 10% of any cost savings under the bid price of \$16.9 million. The RFP Team was not allowed to consider any potential customer savings due to the utility self-build project costs coming in under the bid price, and the self-build proposal was selected based on the full \$16.9 million capital price. The potential for customers to realize 10% of any capital cost savings is an additional benefit of the project which would not be provided by an independent power producer ("IPP").

2. O&M

The annual O&M costs for the Project, which were included in the successful bid, are detailed in Exhibit 5. The amounts detailed are proposed as capped amounts. In the event that actual annual O&M costs are less than these amounts, the Company has proposed a Shared Savings Mechanism through which customers would realize 10% of any cost savings under the bid O&M amounts. The RFP Team was not allowed to consider any potential customer savings due to the utility self-build project costs coming in under the bid price, and the self-build proposal was selected based on the full O&M pricing provided. The potential for customers to realize 10% of any O&M cost savings is an additional benefit of the project which would not be provided by an independent power producer ("IPP").

3. Revenue Requirements

The resultant revenue requirements for the Project, which were calculated in the bid and served as the basis for selection, are detailed in Exhibit 5.

4. Net Costs

The Company seeks recovery of Project costs through the MPIR mechanism. Under the MPIR Guidelines, any cost savings that would be realized due to the Project's implementation should be returned to customers. For cost savings such as reduced purchased power or reduced fuel costs, this is accomplished through an existing mechanism such as PPAC or ECRC. For other costs, recovery of a project's actual costs is offset by the expected cost reductions that the utility expects to realize through implementing the proposed project.

In order to be consistent with how an IPP would be compensated, the Company seeks recovery of the full amount of the Project costs upon which the successful bid was based, without any offset for any expected utility cost savings that may result from the Project's implementation.

Because the Project is a contingency reserve resource, the expected utilization of the Project cannot be accurately predicted. As a result, any expected changes in purchased power or fuel use are not estimated in this Application. Regardless, any fuel or purchased power cost changes will flow back to customers through PPAC and ECRC.

SUMMARY

The proposed Project provides Hawai'i Island customers a required grid resource at the lowest price available, and should be approved on this basis.

Exhibit 8 Community Outreach Plan

While no communities would be directly affected by the proposed project as there are no existing developments, uses, or activities other than power generation and transmission occurring on the project site currently, Hawai‘i Electric Light intends to engage community stakeholders in the project and seek comment, questions, and feedback to share with the RFP team.

Communities that would be indirectly affected include:

- Those able to see the facility from their homes, places of business, or when travelling in the area. As mentioned, visual impacts would be nominal as the area is remote and does not appear in identified view planes.
- Travelling public on roads that would be utilized for delivering equipment to the site during construction. The impact will be temporary and not significant.
- Hawai‘i Electric Light customers. Customers will benefit as the project may assist the company in achieving renewable energy goals and decommissioning of fossil fuel powered generating stations.

Although there are no communities that will be directly affected, Community Outreach and Engagement is planned for this project as follows:

- Communication/smaller meetings to take place with Government Officials, Community leaders, and other specific Stakeholders local to the area to discuss details and benefits of the project, as well as gather feedback from said individuals.
- Based on feedback from smaller engagements, additional public meetings may be planned to engage those who may have concerns about the project. Notice of the meeting will be at least 30 days in advance to allow for those in attendance to submit any written comments/statements at said meeting should they want their statement submitted along with the company’s application to the PUC. NOTE: Due to physical distancing measures for COVID-19 and state mandate to shelter in place, the in-person public meeting was instead planned as a virtual meeting in the interest of public health and safety.

- Subsequent to the PUC Submittal Date and prior to the date when the Parties' statements of position are to be filed in the docketed PUC proceeding for this Project, the public will be encouraged to, and given the opportunity to submit comments concerning the Project, a second time.

Throughout the duration of the project, a contact group will be designated as the public contact to address any questions and/or concerns that may arise concerning the project.

Self-Build Team Community Outreach Contact:

- Community Relations Specialist: Darren Elisaga
- Contact Information: Darren.Elisaga@hawaiielectriclight.com

Other Consultants:

Planning Solutions has been contracted to assist with the Community Outreach efforts. They have extensive experience working with communities in Hawaiʻi and the cultural sensitivities that must be taken into account. They have worked in focused consultations as well as larger public meetings.

All inquiries/concerns and developments that may come up during the construction process will be documented. All resolutions to said concerns or opposition that may come up will be documented. All events and project progress will be documented, and available in chronological order as to develop a timeline for both projects.

A clear record will also help the team to determine if any individual or stakeholder group has been missed in the process. Lastly, the outreach record may be needed to demonstrate that efforts to genuinely engage the community were made and can show the details of those efforts.

Local community support or opposition.

The Community Relations Specialist will continually assess the community's temperature regarding the project and keep the project team informed. Any issues that appear to be escalating or have the potential to do so will be addressed as expediently as possible to avoid negative attention towards the proposed project. Monitoring social media for any misinformation will be key to preventing unnecessary conflict around the project.

Detailed community outreach efforts:

March 1, 2020

- www.hawaiianelectric.com/selfbuildprojects launched
- keaholebess@hawaiianelectric.com email activated

March 27, 2020

- News release announcement on virtual meeting details
- Promotion of virtual meeting via Hawaiian Electric social media platforms
- PowerPoint presentation with notes added to website

April 3, 2020

- Individual letters with details on both BESS projects, and the virtual meeting details sent out to Government Leaders, Community Leaders, and Project Area Stakeholders

April 12, 2020

- Virtual meeting details promoted via a paid public notice in West Hawaiʻi Today and Hawaiʻi Tribune-Herald (Hawaiʻi Island newspaper publications)

April 15, 2020

- Interactive virtual public meeting held on Nā Leo TV
- Rebroadcasts of the virtual public meeting on Nā Leo TV ran daily between 4/15/20 – 4/22/20, and on 4/24, 4/25 & 4/29:

Nā Leo TV, Channel 53	
Friday, 4/17/2020	9:00 a.m.
Sunday, 4/19/2020	1:00 p.m.
Tuesday, 4/21/2020	11:00 a.m.
Nā Leo TV, Channel 54	
Thursday, 4/16/2020	10:00 a.m.
Saturday, 4/18/2020	6:00 p.m.

Monday, 4/20/2020	8:00 a.m.
Wednesday, 4/22/2020	3:00 p.m.
Friday, 4/24/2020	7:00 p.m.
Saturday, 4/25/2020	3:30 p.m.
Wednesday, 4/29/2020	1:30 p.m.

Ongoing:

- Monitor keaholebess@hawaiianelectric.com email
- Respond to community and government questions, concerns, feedback
- Update the website, including FAQs
- Public relations/publicity – respond to media inquiries and/or arrange interviews with SMEs, as needed
- Plan for any in-person meetings if necessary when restrictions for COVID-19 are lifted.

Future Activities:

- Stakeholder and community notification that the Application has been submitted
- Solicitation of additional comments for 30 days, and provision of responses
- Filing of additional comments and responses to the application

Exhibit 9: Public Comments, Questions, and Responses

Note: The virtual public meeting provided information on the Keahole BESS and another self-build proposal, the 6MW Puna BESS, which was not selected. Therefore, some of the questions refer to both proposals together, and some to one or the other of the proposals.

Questions and Responses During Keāhole BESS Virtual Community Meeting

1. How was the 18MW size ultimately determined as the optimum size for this island?
    a. The size was determined by several system characteristics including the amount of PV inverters that do not have the current required ride-thru operational characteristics. It's the minimum size to keep our system stable during events.
    b. The size was determined by the RFP team based on the needs of the grid. The Self-build team responded to the requirements of the RFP.
2. Vertical stacking considered? Less footprint?
    a. Yes. However, this is not recommended by the vendor for the system we are proposing. The batteries are stacked vertically inside the container enclosures. It is also more susceptible to damage by hurricane or earthquake.
3. Do we have enough land, so we won't need to stack them?
    a. Yes, we have enough. Stacking is not recommended. It gets expensive and increases the liability by being more susceptible to earthquakes and hurricanes.
4. What is estimated life cycle for battery project
    a. This BESS system is currently set to operate for a duration of 20yrs. At that time, or most likely prior, we can negotiate renewing the terms of the battery system and its need.
5. What happens to battery at the end of its life?

a. At the end of the 20-year term we can extend the contract or dismantle the site. If decommissioning is preferred, then battery vendor will be responsible for disposal.

6. Any consideration of the brush fires so prevalent in the area?

    a. Fire safety is always a concern when doing ANY project. This is no different. We will involve local authorities and any other stakeholders

7. Are these batteries protected from a category 5 hurricane?

    a. Yes, these modules are rated for windspeed up to 157 mph.

8. Where is the dead battery facility (for recycling & disposal)?

    a. All cells no longer in use will be sent back to the manufacturer's facilities in the mainland

9. What sources of firm power does the Big Island have?

    a. Currently we have Keahole combustion turbines and Steam turbines. We also have Kanoelehua's Hill 5 and 6. We have Hamakua Energy Partners in Hamakua.

10. Why not 2-way EV charging instead?

    a. The issue with EV charging for this use case is there is no way to guarantee that we will have the required 18MW connected to the system. This method has been looked into and it is just not reliable enough for this purpose.

11. How much above sea level is the site, & is there any guarantee that there will be no salt related deterioration?

    a. The Kona site is approx. 200' above sea level and the Puna site is approx. 200'. Proper operation, maintenance, and repair are all part of the contract with the

BESS vendor. Vendor has stated that they have installed this system in harsh environments with little issues of deterioration.

12. Will this new project create additional grid capacity for new solar projects?
    a. Not necessarily. With the addition of the BESS we will be better suited to respond quickly to disturbances on the grid and mitigate the effects of existing legacy PV. It makes the grid more stable to operate, but doesn't necessarily create additional capacity. Additional BESS will be needed for new solar projects.
13. How does the 18 MW battery capacity compare to the overnight demand for electricity for the island?
    a. The 18MW battery capacity is much lower than the overnight peak demand for electricity for the island of about 180MW. This BESS is not meant to cover loads for nighttime demand, but instead a reserve.
14. What would the normal loads look like with the BESS system? What's the system peak normal and now with Covid19 and what will the BESS systems allow for? Better ride through capability?
    a. The BESS would prevent some outages when units trip. You may have noticed some outages these past couple of weeks. This was due to generators tripping offline due to safety concerns of damage to the generators. If this BESS was installed during these events, our customers would most likely have not experienced an outage. (Note: Outage was less than 3 minutes)
15. How many stand-alone batt systems has HECO currently developed?
    a. Currently we have 1 in operation at HRD.

16. What if the contract is renewed? Do they install new modules or will the contractor install a new set of batteries?

17. Has HELCO considered gravity pump storage instead?

    a. Yes. Pump storage hydro has been considered. Although not new technology, it has proven effective in keeping steady power. Typically, this method is used as a load shifting, frequency regulation, and energy storage mechanism.

18. How much power can be stored, how long can it keep our island energized, what percentage of island at peak demand?

    a. This battery is used for contingency events, and not designed to keep the island energized. There will be a maximum of 18 MW of energy at any given time available when an event occurs to automatically respond in case of an event on the system

    b. We don't dispatch this energy like the load shift. The unit automatically dispatches but for the most part, we keep it stored all day every day until we need it for an event.

19. With the goal of 100% renewables, Will there be more support for rooftop PV

    a. The addition of the BESS will allow for more rooftop PV to be installed. However, currently there is no limit to the amount of PV that can be installed on a given circuit.

20. How does the capacity for this system compare to night & day loads for this island?

    a. The size of the system was identified by a study done to reduce excessive customer outages and possible system failure caused by high penetration DER.

The 18MW of storage are the needs of the island grid to survive a contingency situations and duration to bring standby generation online.

21. What are the daytime loads currently?
    a. We have seen minimum loads of less than 80 MW. What about when the weather is cloudy or rainy
22. How is Hawaii Electric planning to handle the increased construction traffic, at this challenging intersection?
    a. If we win the bid, we can review this in further detail. However, we don't feel that there is a need for additional traffic control at this location other than when transporting equipment and material.
23. How does the storage capacity (12 MW) relate to average single home use/how many single family residences could be supported by the storage?
    a. This project is not intended to be a supply for the general distribution of power. It serves as a contingency for power in case a generator (fossil fuel, wind, Hydro, etc.) trips offline.

<u>Questions and Responses After Keahole BESS Virtual Community Meeting</u>

1. If all energy generation becomes renewable with no firm power, how much more battery storage would be needed?
    a. First, we need to define "firm power." The term 'Firm power' as it applies to the area of energy can be defined as 'Power or power-producing capacity, intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions'.

b. Knowing this we would never be without Firm power. We would have "firm power" by way of geothermal and bio-diesel units which are both renewable firm power.

2. Would you use other storage methods such as pumped hydro?

a. We have explored options like these in the past. However, they were thought to be unfeasible. This is primarily due to the high cost of construction for its use case. The attainment of land for the reservoir(s) and its proximity to the transmission system is never an easy task. This method of energy storage is primarily for peak shaving and not for contingency as the RFP is requesting.

3. Will there be any new power lines associated with these projects?

a. No. We are not proposing any new power lines to be built for this project. The BESS will be collocated on Hawaiian Electric property with existing switching stations. This is where we plan to interconnect the system.

4. What's the difference or connection between the self-build team at HELCO and the Current - HECO subsidiary?

a. They are two completely different entities. We, the self-build, team are still Hawaiian Electric employees. However, there are barriers in place that don't allow us to communicate with others on the RFP about the BESS project as to taint the integrity of the RFP process. We also have stricter guidelines that we need to adhere by. For instance, we need to do community outreach prior to winning the bid, we need to submit our proposal prior to any other vendor.

5. In last couple of years there have been some high-profile safety related issues with battery storage including explosion in Arizona and in South Korea – is there any data

readily available for review regarding safety. By the way, I understand and support this project, just asking.

a. In order for the batteries to ignite their needs to be a breach in its initial casing much like a AA battery has. This casing is enclosed in a crush rated "pod" enclosure where there are multiple batteries. Those "pods" are then stacked on racks within a shipping container. So, you see, it will take a lot of force to crush a container, then the rack holding the pods, then the pods, and then the batteries themselves. The batteries themselves have a safety feature which ties them (much like a fuse) from the array. Thus there are many safety features that we have considered when making our decision.

6. What is done to prevent fires?

   a. The battery system is in compliance with all current fire protection standards.

7. What is the plan for fire-fighting and evacuation if needed?

   a. We will have to work with the local authorities having jurisdiction on this. The vendor will work with us on this as a standard safety procedure.

8. What percent of island electric needs will this project meet--now and in the future after many people get rooftop solar, and microgrids are built?

   a. This RFP is calling for a contingency battery. This means that this project will not "meet any needs" as far as demand is concerned. This project is to minimize disruptions to the grid should a generator unexpectedly trip offline.

9. What kind of construction work and permits are needed to build the projects on the two sites?

a. Although Utilities are exempt from standard building permitting procedure, we will include the county in this building process.

10. Will these batteries make any noise?

    a. No. these batteries do not make any noise.

11. What are these batteries made of?

    a. The technology that we have proposed is Lithium-ion. Currently it has the best benefits of cost, weight, response speed needed to be competitive with this RFP.

12. How big is the battery... size, weight, height...?

    a. These batteries will be housed in a shipping container sized enclosure.

13. Will the batteries be visible from street view?

    a. For the Keahole site, I don't think you will be able to view it from any public road.

14. What happens if there is an earthquake? Can they withstand an earthquake?

    a. These batteries have adequate seismic ratings necessary for installation on the Big Island.

Hawaiian Electric Company, Inc. hereby identifies redacted confidential information that will be submitted confidentially upon issuance of a Protective Order in this proceeding. This log (1) identifies, in reasonable detail, the confidential information's source, character, and location; (2) states clearly the basis for the claim of confidentiality; and (3) describes, with particularity, the cognizable harm to the producing party or participant from any misuse or unpermitted disclosure of the information.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit 2	Project Cost Summary	Confidential cost and financial information which falls under the frustration of legitimate government function exception of the Uniform Information Practices Act ("UIPA").[1]	Disclosure of the confidential information to the general public could disadvantage and competitively harm the Company, impact the Company's bargaining power relative to other vendors, place the Company at a competitive disadvantage in future proposals and contract negotiations, and harm the Company's relationships with existing and/or prospective vendors and/or customers. Moreover, disclosure of the confidential information could result in the Company paying increased amounts for the same products and services in the future, which would increase costs for the Company and its customers. In addition, public disclosure of this information may discourage vendors from doing business with the Company, discourage vendors from making confidential disclosures to the Company, and expose the Company to certain liabilities. Further, public disclosure of the confidential information would provide a roadmap, enabling competitors to not provide their best price in response to subsequent RFP's, but rather a price at or slightly below what is offered by Company. The Company contends that disclosure of the information will not only harm the Company competitively, but also have an adverse impact on subsequent RFPs.

[1] Haw. Rev. Stat. § 92F-13(3)

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit 3, tabs 1 – 3 and 5 - 10	MPIR Model	Confidential cost and financial information which falls under the frustration of legitimate government function exception of the Uniform Information Practices Act ("UIPA").[2]	Exhibit 3 reflects confidential cost information and methodologies, the disclosure of which to the general public could disadvantage and competitively harm the Company, impact the Company's bargaining power relative to other vendors, place the Company at a competitive disadvantage in future proposals and contract negotiations, and harm the Company's relationships with existing and/or prospective vendors and/or customers. Moreover, disclosure of the confidential information could result in the Company paying increased amounts for the same products and services in the future, which would increase costs for the Company and its customers. In addition, public disclosure of this information may discourage vendors from doing business with the Company, discourage vendors from making confidential disclosures to the Company, and expose the Company to certain liabilities. Further, public disclosure of the confidential information would provide a roadmap, enabling competitors to not provide their best price in response to subsequent RFP's, but rather a price at or slightly below what is offered by Company. The Company contends that disclosure of the information will not only harm the Company competitively, but also have an adverse impact on subsequent RFPs.

[2] Haw. Rev. Stat. § 92F-13(3)

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit 5, tabs 1, 2, 4, 5, 7, and 8	Revenue Requirements and Bill Impact	Confidential cost and financial information which falls under the frustration of legitimate government function exception of the Uniform Information Practices Act ("UIPA").[3]	Exhibit 5 reflects confidential cost information and methodologies, the disclosure of which to the general public could disadvantage and competitively harm the Company, impact the Company's bargaining power relative to other vendors, place the Company at a competitive disadvantage in future proposals and contract negotiations, and harm the Company's relationships with existing and/or prospective vendors and/or customers. Moreover, disclosure of the confidential information could result in the Company paying increased amounts for the same products and services in the future, which would increase costs for the Company and its customers. In addition, public disclosure of this information may discourage vendors from doing business with the Company, discourage vendors from making confidential disclosures to the Company, and expose the Company to certain liabilities. Further, public disclosure of the confidential information would provide a roadmap, enabling competitors to not provide their best price in response to subsequent RFP's, but rather a price at or slightly below what is offered by Company. The Company contends that disclosure of the information will not only harm the Company competitively, but also have an adverse impact on subsequent RFPs.

[3] Haw. Rev. Stat. § 92F-13(3)

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAIʻI

In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC. For Approval to Commit Funds in Excess of $2,500,000 for the Purchase and Installation of Item HZ.005027 Keāhole Battery Energy Storage System Project, and to Recover Costs through the Major Project Interim Recovery Adjustment Mechanism	 DOCKET NO.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Application, Verification and Exhibits 1- 9, together with this Certificate of Service, was duly served on the following party by electronic mail service as set for below:[1]

Division of Consumer Advocacy
Department of Commerce and Consumer Affairs
335 Merchant Street, Room 326
Honolulu, Hawaiʻi 96813
dnishina@dcca.hawaii.gov
consumeradvocate@dcca.hawaii.gov

DATED: Honolulu, Hawaiʻi, August 28, 2020.

HAWAIIAN ELECTRIC COMPANY, INC.

/s/ Richard VanDrunen

Richard VanDrunen
Regulatory Affairs

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[1] As stated in Order No. 37043 *Setting Forth Public Utilities Commission Emergency Filing and Service Procedures related to COVID-19* (non-docketed), issued on March 13, 2020 at 11: Service of all documents filed by any parties, participants, utilities, stakeholders and/or other entities or individuals shall be via email. All entities making filings before the commission will be required to supply an email address that can be used for service. Any Certificates of Service for docketed or other matters that previously had listed the entity's name and the physical address where a document was served via first-class mail, shall instead reflect the entity's representative's name, entity name, email address where served, as well as the date of service.