STATE OF HAWAII
PUBLIC UTILITIES COMMISSION

REPORT TO THE 2024 LEGISLATURE RELATED TO AN INTERCONNECTION STUDY AND PROGRESS ON CONTRACTING THE HAWAII ELECTRIC RELIABILITY ADMINISTRATOR (HERA) PURSUANT TO ACT 201 (2022)

DECEMBER 2023

Table of Contents

Background

During the 2022 Legislative Session, the Hawaii State Legislature passed Senate Bill ("SB") 2474 SD 2 HD 1 CD 1, which was signed into law on June 27, 2022 as Act 201.[1] The law requires that the Public Utilities Commission ("Commission") contract with a qualified consultant to conduct a study on the accessibility of Hawaii's electric system and procedures for interconnection to Hawaii's electric system, including but not limited to the timeliness and costs of interconnection.

The law states that the Commission shall submit the study required by Act 201 and a report, including its progress in contracting an entity to serve as the Hawaii Electric Reliability Administrator ("HERA") pursuant to Hawaii Revised Statute ("HRS") Section 269-147, to the legislature no later than twenty days prior to the convening of the regular session of 2023.

The interconnection evaluation was conducted in two phases, and the Commission submitted the Phase 1 report to the 2023 Legislature in December 2022.[2] This Phase 2 report builds on the previous findings and recommendations and addresses the remaining issues of Act 201 not covered in the Phase 1 report. This report includes the full study conducted by the qualified consultant and an update on the Commission's progress in contracting a HERA entity.

Section 1: Act 201 Study

I. Qualified Consultant

The Commission hired PA Consulting Group Inc. ("PA Consulting") to conduct the study required in Act 201. PA Consulting responded to a Request for Proposal ("RFP")[3] issued on July 1, 2022, to serve as an Independent Engineer ("IE") for the Hawaiian Electric Companies ("Companies", or collectively "Hawaiian Electric") Stage 3 Request for Proposals (RFPs).[4] Given the significant overlap between the scope of the Act 201 study and the areas of oversight envisioned for the IE, the Commission included the Act 201 study as a component of the IE's proposed scope of work. Offers in response to the IE RFP were due on August 1, 2022, and the Commission completed its review of qualifying offers, selected PA Consulting, and executed a contract with PA Consulting in October 2022.

II. Study Scope

PA Consulting suggested in its Best and Final Offer that it would be efficient to conduct the Act 201 study in two phases due to timing and budget constraints. The Commission agreed with this phased approach given the breadth of required components and recommendations enumerated in Act 201 and the overlap in study areas with the work that the IE would conduct related to the Stage 3 RFPs. PA Consulting completed the Phase 1 Act 201 Study and submitted it to the Hawaii State Legislature ahead of the 2023

[1] See Act 201, available at: https://www.capitol.hawaii.gov/sessions/session2022/bills/GM1302_.PDF.
[2] See Phase 1 Act 201 Study, available at: https://puc.hawaii.gov/wp-content/uploads/2022/12/Act-201-Report-with-Attachment.pdf.
[3] See RFP for IE, available at: https://hands.ehawaii.gov/hands/opportunities/opportunity-details/21686.
[4] The Hawaiian Electric Companies' Stage 3 RFP is a competitive procurement process that allows market participants to bid utility-scale renewable projects in a competitive solicitation to enable the retirement of large capacities of fossil fuel generation on Oahu, Maui, and Hawaii Island. The Commission is responsible for ensuring these competitive procurements are carried out following a fair set of guidelines to achieve shared benefits for the participants in the bidding process and communities that will be impacted by the development of these projects.

Legislative Session.[5] PA Consulting continued its study efforts in 2023 in order to complete the Phase 2 Act 201 Report, including conducting in-depth interviews with stakeholders.

III. Study Recommendations

The Act 201 Study Report includes the following recommendations from PA Consulting to address near-term issues related to Hawaiian Electric's interconnection process and reliability standards:

Improvement Area	**Recommendation**
Companies' Interconnection Requirements	"The Companies should review interconnection related tariff/rules and revise, if necessary, to provide technical clarity in terms of interconnection requirements. For example, expand and include technical interconnection requirements into Rule No. 19, or into a new generic transmission and sub-transmission interconnection tariff, to capture all the requirements in one document, similar to how Rule No. 14 Tariff (Rule No. 14) captures the technical interconnection requirements for connection on the distribution level. The Reliability Standards Working Group's (RSWG) Report also recommended that the interconnection tariffs – including Rule No. 14 and Rule No. 19 – be revised to be more consistent with each other and inclusive of the overall process requirements. The revisions will provide project developers clarity regarding interconnection requirements and which take precedence. The Commission should perform an interconnection procedures and cost benchmark study to understand renewable energy integration metrics scoring criteria and opportunities to streamline processes from other jurisdictions. Such benchmarks could be obtained from jurisdictions that have similar regulation, decarbonization, or landscape characteristics as Hawaii."
Companies' Interconnection Process	"The Companies should consider providing adequate interconnection related information to the bidders in an easily accessible way during the pre-bid period via a templatized "Pre-Application" report at the interested Point of Interconnection (POI) or substation. The "Pre-Application" report for developers could include helpful information for planning interconnection designs such as POI/substations within the area, peak loads, existing generation and pending installs, total available capacity, voltage and circuitry, regulation equipment and communication devices, protective devices, any limitations or constraints, etc."
Companies' Interconnection Requirements	"The Companies should consider using a multi-step approach to request interconnection data from the bidders. The multi-step approach will help streamline and enhance the Companies' interconnection process and provide value by reducing the cost of bid preparations, thus encouraging submission of more bids in future RFPs. The Companies could organize interconnection data collection such that only the absolute minimum required data is collected first and more detailed information is collected when the winning bid proceeds to construction phase."

[5] See Act 201 Study Phase 1, available at: https://puc.hawaii.gov/wp-content/uploads/2022/12/Act-201-Report-with-Attachment.pdf

Interconnection Costs	"The Companies should develop comparable interconnection cost metrics for self-build and Independent Power Producer (IPP)-built projects so that interconnection costs can be directly compared. The Companies should track the total interconnection cost of the self-build projects separately by IRS, COIF and SOIF costs so that appropriate components can be compared with the IPP-built projects."
Interconnection Costs	"To enhance the accuracy of interconnection cost in the Power Purchase Agreement (PPA) price for Utility-Scale projects, the Commission could consider two different options. First, the Commission could explore the possibility of allowing the incorporation of interconnection costs in PPA prices into procurement negotiations following the completion of the System Impact Study (SIS) and the Facilities Study (FS). Second, the Commission could explore the possibility of either separating the interconnection process from the RFP process or allowing developers to have the opportunity to amend and renegotiate PPAs to reflect the trued-up interconnection costs thereby allowing PPAs to reflect the actual interconnection costs."
Interconnection Process Reporting	"The Companies could develop a concise centralized location for bidders to understand the interconnection process. This could include various information including interconnection requirements, bid evaluation methods, and dispute resolution process, and status on projects that are undergoing the interconnection process. It can also include a dashboard and/or interconnection capacity analysis tools for public viewing and planning. The online location could also have a live interconnection portal for transparency and ease of access."
Interconnection Process Reporting	"To enhance the monitoring of the interconnection process, the Commission could explore the possibility of establishing a simplified centralized hub hosted within the Companies' or the Commission's IT system to consolidate and share interconnection reporting materials received from the Companies. Currently, the Commission monitors the interconnection process through various docketed proceedings, monthly reporting, and via the RFP process."
Interconnection-Related Dispute Resolution Process (IDRP) for Utility-Scale Projects	"The Companies should share the established IDRP with developers by communicating directly with the bidders of Stage 3 RFP process. For any future RFP process, the Commission should ensure that the Companies include the established IDRP process in the RFP document. The Commission should also consider continuing the use of the IDRP framework for the future RFP projects beyond Stage 3."
Interconnection-Related Dispute Resolution for CBRE Projects	"The Commission should consider developing an IDRP framework for CBRE projects similar to that which was recently developed for RFP Stage 3."
Interconnection-Related Dispute Resolution	"The Commission should also take steps to raise awareness about the IE and its role to improve the outcomes of the technical aspects of the RFP and interconnection processes."

Reliability Standards	"The Commission should develop a more systematic approach to enforcing reliability standards by revisiting the work completed by the RSWG, via Docket Number 2011-0206, and assess how the reliability standards are currently being implemented or reported, and whether some of the standards originally developed ten years ago should be replaced with new and current standards. The Commission should re-evaluate and propose updated reliability standards based on findings from subsequent proceedings, such as the IGP process. The Commission should also continue to explore cost-effective ways to implement the additional aspects of the HERA scope, including updating and enforcing reliability standards and overseeing system operations."

IV. Next Steps

The Commission is currently pursuing many of these recommendations and will continue to address the recommendations that are directed to Hawaiian Electric through various proceedings related to future procurements and the current interconnection process to ensure fair and equitable outcomes for all participants in these processes, as well as Hawaiian Electric's customers. The Commission also plans to raise awareness about the role of the Independent Engineer and the Interconnection-related Dispute Resolution Process through direct outreach to participants in the RFP and interconnection processes.

In response to PA Consulting's final recommendation regarding reliability standards, the Commission continues to review the effectiveness and enforceability of reliability standards and is exploring new standards as discussed in Section 2. Through continued work with the IE in the Stage 3 RFPs, the Commission will implement policy measures to improve the interconnection process and internal processes utilized by Hawaiian Electric in its current and future RFPs.

Reader's Note: In Section 5, the Act 201 Study provides status updates of all projects under development as of November 15, 2023. Therefore, these updates do not include the withdrawal of the Paeahu Solar project on Maui[6] nor the Commercial Operations Date achievement of Kapolei Energy Storage on Oahu.[7]

[6] Innergex and Hawaiian Electric mutually agreed to terminate the Paeahu Solar project and filed notice on November 28, 2023, available at: https://shareus11.springcm.com/Public/DownloadPdf/25256/a60beb61-5c8e-ee11-b83e-48df377ef808/2a2aaaf5-f68e-ee11-b83e-48df377ef808

[7] Kapolei Energy Storage reached its Commercial Operations Date on December 19, 2023, as noted by the Companies' status update, available at: https://shareus11.springcm.com/Public/DownloadPdf/25256/1329dd8a-b59e-ee11-b83e-48df377ef808/a91978e3-bc9e-ee11-b83e-48df377ef808

Section 2: Commission's Progress on Hawaii Electric Reliability Administrator ("HERA")

Act 201 requires that the Commission include in this report its progress in contracting an entity to serve as the HERA.

I. Progress Update

The Commission issued a Request for Information ("RFI") on February 23, 2022, to solicit input from qualified entities to potentially serve under contract as the HERA. The RFI also sought feedback from experts interested in the development, administration, or management of a process, program, or system similar to that envisioned for the HERA.[8] The Commission received responses from entities under both categories. After responses were due on April 8, 2022, Commission staff engaged in follow-up discussions with the responding entities and conducted additional research on analogous entities to the HERA in other jurisdictions. In the RFI, the potential scope of the HERA outlined key issue areas aligned with statute including, but not limited to, reliability standards, interconnection oversight, and grid operations oversight.

With Hawaiian Electric receiving bids for its Stage 3 RFPs in early 2023 and limited information on the total cost of the HERA, the Commission elected at that time to pursue a narrowed scope for the near-term. Concurrently, stakeholders were providing the recommendation to hire an IE to support the development of Hawaiian Electric's Community Based Renewable Energy ("CBRE") and utility-scale renewable projects. The Commission contracted with two entities to serve as the IE for the Stage 3 RFPs and CBRE RFPs, respectively, to perform the interconnection oversight and system operations oversight functions of the HERA. The Commission finds the work of the IE to be beneficial and plans to continue employing an IE in future RFPs for renewable projects.

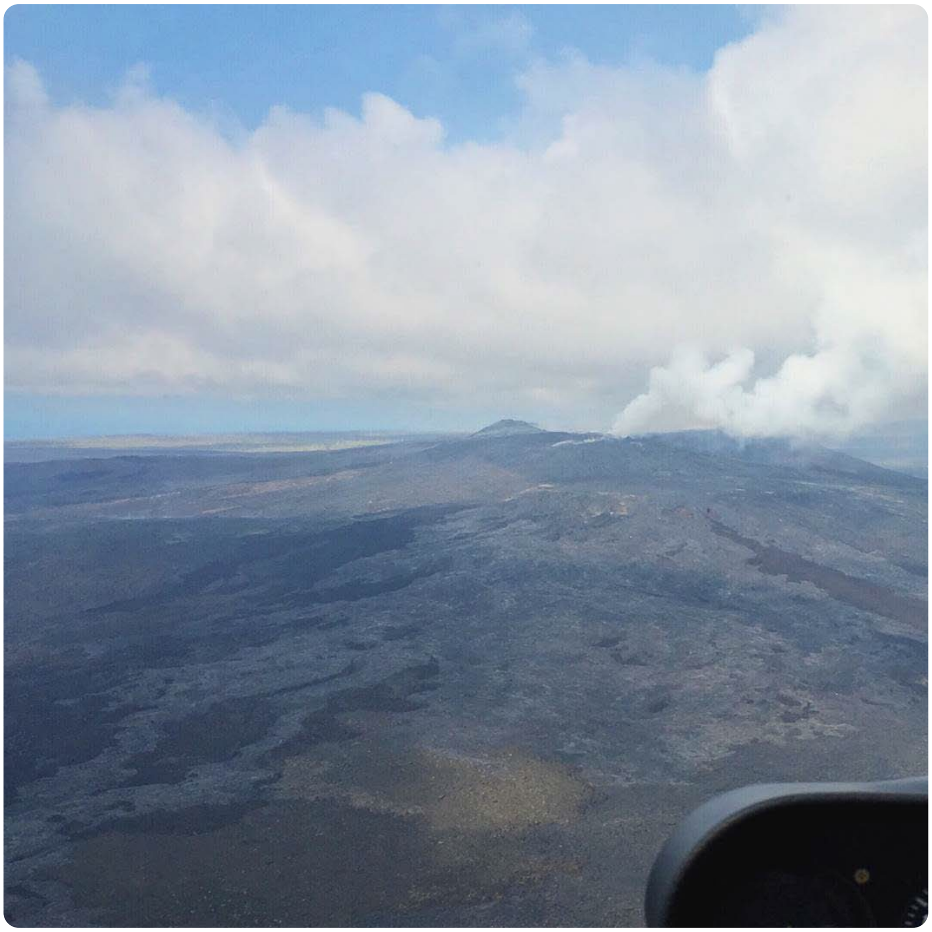
Additionally, the Commission made significant progress developing and refining reliability standards across numerous proceedings. The Commission utilized the Performance-Based Regulation ("PBR") framework to establish incentives and metrics for power supply and system reliability and interconnection study timeliness. The Commission monitors recurring reports from Hawaiian Electric on numerous reliability performance metrics. The Commission investigated the reliability metrics used in Hawaiian Electric's Integrated Grid Planning ("IGP") process, required Hawaiian Electric to study different methodologies for assessing reliability in planning, and intends to investigate the establishment of Hawaii-specific standards within the context of the IGP process to ensure that future investments in the grid will achieve an appropriate balance of reliability and affordability.

II. Next Steps

The Commission will continue to pursue the duties and goals outlined for the HERA through the work of the IE and through the various relevant proceedings (e.g., IGP, PBR). The Commission will also pursue a holistic approach to enforcing reliability standards, while recognizing that reliability is a diverse topic which is measured across several system dynamics and across different utility operations. Most importantly, the Commission will continue to pursue the most cost-effective approach to achieve the goals set out for the HERA in acknowledgement of the potential ratepayer impacts that would result from the formation of the HERA.

[8] See HERA RFI, available at: https://hands.ehawaii.gov/hands/opportunities/opportunity-details/21007.

Attachment A – PA Consulting's Act 201 Study Report



State of Hawaii Interconnection Process Study - Phase 2

Prepared for the Hawaii Public Utilities Commission Per Act 201

December 20, 2023

Bringing Ingenuity to Life.
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Contents

Figures

Tables

Glossary

AFUDC - Allowance for Funds Used During Construction
CBRE - Community Based Renewable Energy
CCRP - Competitive Credit Rate Procurement
COD - Commercial Operation Date
COIF - Company-Owned Interconnection Facilities
D&O - Decisions and Orders
DER - Distributed Energy Resource
EPRM - Exceptional Project Recovery Mechanism
FERC - Federal Energy Regulatory Commission
FS - Facilities Study
GCOD - Guaranteed Commercial Operation Date
GRC - General Rate Case
HERA - Hawaii Electricity Reliability Administrator
HPUC - Hawaiian Public Utilities Commission
HRS - Hawaii Revised Statutes
IDRP – Interconnection-Related Dispute Resolution
IE - Independent Engineer
IF - Independent Facilitator
IPP - Independent Power Producer
IRS - Interconnection Requirements Study
ISO - Independent System Operators
KIUC - Kauai Island Utility Cooperative
LMI - Low and Moderate Income
MPIR - Major Project Interim Recovery
MRP - Multi-Year Rate Period
NERC - North American Electric Reliability Corporation
NTE - Not to Exceed
PBR - Performance Based Regulation
PIM – Performance Incentive Mechanism
PPA - Power Purchase Agreement
RDG - Renewable Dispatchable Generation
RFI - Request for Information
RFP - Request for Proposal
RFP - Request for Proposal
RPS - Renewable Portfolio Standards
RSDG - Reliability Standards Development
RSWG - Reliability Standards Working Group
RTO - Regional Transmission Organizations
SB - Senate Bill
SLD – Single Line Diagram

Executive Summary

On June 27, 2022, former Hawaii Governor David Ige signed into law Senate Bill (SB) 2474 SD 2 HD 1 CD 1 as Act 201, Session Laws of Hawaii 2022 (Act 201). The Act mandates the Hawaii Public Utilities Commission (Commission or HPUC) conduct a study of the State's Interconnection Processes. The Commission engaged PA Consulting Group, Inc. (PA or the Study Team) to assess the State's interconnection processes, evaluate the accessibility of Hawaii's electric utility grid, and identify the timeliness and costs of interconnection.

Act 201 mandates the study to include interconnection issues encountered for renewable generation projects greater than five megawatts and any Community-Based Renewable Energy (CBRE) generation projects of any megawatt size from investor-owned utilities and utilities that serve counties with a population of more than one hundred thousand. Based on the project requirement mandates of Act 201, the interconnection process review applies to the interconnection requirements established by Hawaiian Electric Companies ("Hawaiian Electric", or the "Companies") for utility-scale renewable (Utility-Scale) and CBRE projects. This study does not include findings about behind-the-meter renewable resources, nor findings pertaining to Kauai Island Utility Cooperative.

Specifically, Section 1(c) of Act 201 listed out seventeen different interconnection related issues to be evaluated and requested recommendations on fifteen different interconnection related matters.

(1) Include, but not be limited to, reliability standards to be established by the public utilities commission;

(2) Identify interconnection requirements and procedures for interconnection to the State's electric utility grid;

(3) Describe the interconnection process and who is responsible for each element of the process;

(4) Determine the reasonableness of time for each element of the interconnection process;

(5) Determine the reasonableness of the elements and methodology that utilities utilize to charge for interconnection;

(6) Determine the reasonableness and equity of costs charged to those that interconnect to an electric utility;

(7) Include costs of interconnection by an electric utility for the interconnection of the electric utility's self-build projects;

(8) Include reporting and analysis over the previous seven years of the:

> (A) Timeliness of the interconnection process from the execution of the power purchase agreement through the interconnection completion, if applicable, or up through the time that the last step is completed; and
>
> (B) Cost of interconnection of renewable energy projects, including: (i) The charges to those who interconnected or are in the process of interconnecting to an electric utility; (ii) Any project management fees; and (iii) Any other elements that are relevant in the methodology, including but not limited to the size of the project, and the distance to the interconnection point;

(9) Include documentation of the delays in the interconnection process for Stage 1 and Stage 2 renewable procurement projects, including the cause of each delay as well as the party responsible for the delay;

(10) Determine whether any elements of interconnection are currently rate-based;

(11) Determine the reasonableness of the cost of project management fees assessed by an electric utility to those entities that interconnect to the electric utility;

(12) Determine the reasonableness of requiring new or additional interconnection studies for changes in equipment;

(13) Determine what would constitute a reasonable change to cause a new or extended interconnection process;

(14) Incorporate comments from entities who connect to an electric utility in a confidential manner and be reported anonymously in the study;

(15) Report on the implementation of a Hawaii electric reliability administrator to be implemented by the public utilities commission;
(16) Evaluate the public utilities commission's progress in the implementation of a Hawaii electric reliability administrator; and
(17) Recommend statutory amendments to the laws relating to the Hawaii electric reliability administrator.

This report specifically includes the following recommendations in response to Section 1 (d) of Act 201:

(1) Reliability standards that should be considered and imposed by the public utilities commission on an electric utility;
(2) Interconnection procedures;
(3) Reasonable timelines for an electric utility and an entity that interconnects;
(4) How the public utilities commission can monitor the interconnection process;
(5) Processes, data tools, and reporting requirements by the electric utility;
(6) How interconnection costs can be provided to developers prior to the utility procurement process or how to adjust for changes to the power purchase agreement to reflect interconnection costs;
(7) Mechanisms to be imposed by the public utilities commission and the legislature to improve the timeliness of the interconnection process and the reasonableness of cost;
(8) A process to provide transparency in interconnection costs;
(9) Processes for the public utility commission to oversee and approve the cost and timeliness of interconnection;
(10) Whether interconnection costs should be regulated, tariffed, or rate-based for consistency and transparency;
(11) Whether performance incentives, penalties, or both, should be imposed on an electric utility for timely and cost-effective interconnection;
(12) The reasonable interconnection events that would require modification to this study;
(13) The reasonable timelines for modification caused by an electric utility or an entity that interconnects to the State's electric utility grid;
(14) Resolution processes for interconnection disputes; and
(15) Processes, including administrative, technological, policy, or other related requirements for ensuring effective reliability of the Hawaii electric system and interconnection process.

The Commission has also selected PA to serve as an Independent Engineer (IE) for the Companies' ongoing Stage 3 Request for Proposal (Stage 3 RFP) interconnection process for a three-year period (October 2022 – September 2025). In its role of IE for the Stage 3 RFP interconnection process, the Commission tasked PA to oversee various interconnection assignments including, but not limited to, reviewing the Companies' overall interconnection process and technical aspects of the RFP process, developing an interconnection unit-cost guide, and providing insights/advice to the Commission on various interconnection issues. In so doing, PA gained insights related to many of the issues outlined in Act 201.

Due to the overlapping of issues to be analyzed for the study mandated by Act 201 and as an IE, PA and the Commission agreed to conduct the interconnection evaluation in two phases. PA prepared the Phase 1 report in December 2022. Following the completion of the Phase 1 report, PA prepared this report, termed the Phase 2 report (also comprehensively referenced as the "report" or "study"), which serves as the update to the 2022 Act 201 Phase 1 report. In this report, the Study Team built on the previous findings and recommendations and addressed remaining issues of Act 201 not covered in Phase 1 report.

The study period commenced in the fall of 2022 to align with the passing of Act 201. As such, the Study Team compiled findings and recommendations to meet the directives of the statutory implications. The following tables outline both findings and recommendations, respectively.

Table 0-1 includes our summary and key findings from the Act 201 Study.

Table 0-1: Summary and Key Findings

Interconnection Process Areas	Key Findings	Recommendation
State of Hawaii Interconnection Regulatory Policy Refer to Section 2	The State's existing regulatory policy is covered by a combination of decisions and orders addressed to specific interconnection issues within the State, as well as General Order No. 7. As General Order No. 7 addresses a broad range of topics related to electric service, it does not contain expansive regulations related strictly to interconnection, but instead regulates specific aspects that are related to, or are components of, the interconnection process. All of the Companies' requirements related to interconnection are under the jurisdiction of the Commission; the Commission can exert influence over the Companies' internal processes, specifically through the Commission's regulatory authority. In addition to General Order No. 7, there are additional requirements and procedures for construction of high-voltage transmission equipment that is within the jurisdiction of the Commission; this includes, but is not limited to, equipment used to facilitate the interconnection of generation facilities to the electric utility's transmission grid.[1] Additionally, recent state law revised these requirements, stating that the utility does not need Commission approval if the transmission equipment is to be built underground, the entire cost of the underground upgrade is paid for by an entity other than the utility, and the utility provides a report, prior to construction, detailing the project and the funding source.[2] The Commission is also required to conduct a public hearing whenever the utility plans to build a new 46kV or	The Study Team did not find substantial evidence or insights to signal recommendations for the State's interconnection policy or regulatory and/or statutory modifications.

[1] Hawaii Revised Statutes (HRS), §269-27.6.

[2] See Hawaii Revised Statutes (HRS), §269-27.6(d), as revised by Act 65, Session law 2021.

Interconnection Process Areas	Key Findings	Recommendation
	greater transmission line above ground and through a residential area.[3]	
Companies' Interconnection Requirements Refer to Section 3.1	Each Company has a set of tariffs that regulate the interconnection process: Rule No. 14 Tariff (Rule No. 14) and Rule No. 19 Tariff (Rule No. 19). The tariffs are under the Commission's jurisdiction, therefore, any language updates proposed by the Companies are subject to its approval. The Rule No. 19 includes interconnection guidelines and requirements for projects interconnecting to the Companies' system issued pursuant to a Request for Proposal (RFP) process. However, it contains very little information regarding the expectations for all stakeholders during the interconnection process, as well as technical requirements for facilities to interconnect. Furthermore, Rule No. 19 may be superseded by provisions in a Commission-approved RFP process, creating additional uncertainty as to which documents and requirements take precedence for developers who must adhere to such requirements. Unlike Rule No. 14, Rule No. 19 does not contain technical details for interconnection so IPPs must refer to the relevant RFP to find meaningful requirements for interconnecting to the sub-transmission or transmission systems.	The Companies should review interconnection related tariff/rules and revise, if necessary, to provide technical clarity in terms of interconnection requirements. For example, expand and include technical interconnection requirements into Rule No. 19, or into a new generic transmission and sub-transmission interconnection tariff, to capture all the requirements in one document, similar to how Rule No. 14 captures the technical interconnection requirements for connection on the distribution level. The Reliability Standards Working Group's (RSWG) Report also recommended that the interconnection tariffs – including Rule No. 14 and Rule No. 19 – be revised to be more consistent with each other and inclusive of the overall process requirements. The revisions will provide project developers clarity regarding interconnection requirements and which take precedence. The Commission should perform an interconnection procedures and cost benchmark study to understand renewable energy integration metrics scoring criteria and opportunities to streamline processes from other jurisdictions. Such benchmarks could be obtained from jurisdictions that have similar regulation, decarbonization, or landscape characteristics as Hawaii.
Companies' Interconnection Process Refer to Section 3.6	The Companies currently do not have a standardized method to share electric system and POI information to the bidders that are interested in participating in the RFP process.	The Companies should consider providing adequate interconnection related information to the bidders in an easily accessible way during the pre-bid period via a templatized "Pre-Application" report at the interested Point of Interconnection (POI) or substation. The "Pre-Application" report for developers could include helpful information for planning interconnection designs such as POI/substations within

[3] HRS §269-27.5.

Interconnection Process Areas	Key Findings	Recommendation
		the area, peak loads, existing generation and pending installs, total available capacity, voltage and circuitry, regulation equipment and communication devices, protective devices, any limitations or constraints, etc.
Companies' Interconnection Requirements Refer to Section 3.6	For the Stage 3 RFP process, the Companies required all bids to provide interconnection and technical related data with the initial bid submission. The Companies requested numerous technical data related to interconnection. These are outlined in Appendix B Attachment 2b of the Stage 3 RFP document.[4] This process is set up as a single step which collects all possible technical information required to not only perform interconnection studies, but also to design, procure equipment, and fully construct and operate the plant proposed by the bidders.	The Companies should consider using a multi-step approach to request interconnection data from the bidders. The multi-step approach will help streamline and enhance the Companies' interconnection process and provide value by reducing the cost of bid preparations, thus encouraging submission of more bids in future RFPs. The Companies could organize interconnection data collection such that only the absolute minimum required data is collected first and more detailed information is collected when the winning bid proceeds to construction phase.
Interconnection Costs Refer to Section 5.2	Currently, only the total interconnection costs of self-build projects are reported to the Commission whereas the interconnection costs of IPP-built projects reported to the Commission include the breakdowns for IRS and COIF cost components.	The Companies should develop comparable interconnection cost metrics for self-build and Independent Power Producer (IPP)-built projects so that interconnection costs can be directly compared. The Companies should track the total interconnection cost of the self-build projects separately by IRS, COIF and SOIF costs so that appropriate components can be compared with the IPP-built projects.
Interconnection Costs Refer to Section 3.6	The Companies' current method for studying project interconnection – by identifying potential impacts to the grid and determining upgrades needed to ensure safe interconnection – leaves many unknowns in the current RFP process, thus making it difficult to determine accurate interconnection costs and to enable fair PPA negotiations.	To enhance the accuracy of interconnection cost in the Power Purchase Agreement (PPA) price for Utility-Scale projects, the Commission could consider two different options. First, the Commission could explore the possibility of allowing the incorporation of interconnection costs in PPA prices into procurement negotiations following the completion of the System Impact Study (SIS) and the Facilities Study (FS). Second, the Commission could

[4] For example, please refer Appendix B, Attachment 2a of Hawaii Island Stage 3 RFP via this source: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/selling_power_to_the_utility/competitive_bidding/20230228_hawaii_stage_3/20230322_appx_b_proposers_resp_pkg.pdf

Interconnection Process Areas	Key Findings	Recommendation
		explore the possibility of either separating the interconnection process from the RFP process or allowing developers to have the opportunity to amend and renegotiate PPAs to reflect the trued-up interconnection costs thereby allowing PPAs to reflect the actual interconnection costs.
Interconnection Process Reporting Refer to Section 3.4	The Companies rely on time-stamped notices, such as email communications, to maintain records of the different milestones for the interconnection process; they do not maintain a database to store this information. They also maintain a workbook to memorialize the different milestones for each active project that has not yet reached COD. Developers reported mixed experiences with the Companies' communication efforts with some reporting a generally positive experience and others reporting of inconsistencies when moving to different divisions of the Companies. These experiences vary by island and interconnection team.	The Companies could develop a concise centralized location for bidders to understand the interconnection process. This could include various information including interconnection requirements, bid evaluation methods, and dispute resolution process, and status on projects that are undergoing the interconnection process. It can also include a dashboard and/or interconnection capacity analysis tools for public viewing and planning. The online location could also have a live interconnection portal for transparency and ease of access.
Interconnection Process Reporting Refer to Section 3.4	The Commission monitors the interconnection process through docketed proceedings, as well as through multiple entities hired to provide oversight on the RFP and interconnection processes. The docketed proceedings through which the Commission monitors the interconnection process include RFP Dockets (e.g., Docket No. 2017-0352 for Stages 1, 2, and 3 RFPs and Docket No. 2015-0389 for CBRE RFPs), Interconnection Docket (Docket No. 2021-0024), PPA Dockets, PBR Docket (2018-0088).	To enhance the monitoring of the interconnection process, the Commission could explore the possibility of establishing a simplified centralized hub hosted within the Companies' or the Commission's IT system to consolidate and share interconnection reporting materials received from the Companies. Currently, the Commission monitors the interconnection process through various docketed proceedings, monthly reporting, and via the RFP process.

Interconnection Process Areas	Key Findings	Recommendation
Interconnection-Related Dispute Resolution for Utility-Scale Projects Refer to Section 3.5	Following the recommendation from the Act 201 Phase 1 report, the Commission directed the IE to establish an interconnection-related dispute resolution process to address any disputes specifically related to technical interconnection issues between the Companies and project developers. As a result, the IE helped the Commission in establishing the interconnection-related dispute resolution process (IDRP). The IDRP process is currently applicable for Stage 3 RFP renewable projects.	The Companies should share the established IDRP with developers by communicating directly with the bidders of Stage 3 RFP process. For any future RFP process, the Commission should ensure that the Companies include the established IDRP process in the RFP document. The Commission should also consider continuing the use of the IDRP framework for the future RFP projects beyond Stage 3.
Interconnection-Related Dispute Resolution for CBRE Projects Refer to Section 3.5	Currently, there is no Interconnection-related dispute resolution process (IDRP) established to mediate disputes that may arise in CBRE interconnection process.	The Commission should consider developing an IDRP framework for CBRE projects similar to that which was recently developed for RFP Stage 3.
Interconnection-Related Dispute Resolution Refer to Section 6.3	The Companies have posted the IDRP process on its website for Stage 3 RFP. However, at the time of the interview, three of the four utility-scale developers that participated in Act 201 survey did not know about the IE and its role in the RFP, nor the IDRP framework that is currently established.	The Commission should also take steps to raise awareness about the IE and its role to improve the outcomes of the technical aspects of the RFP and interconnection processes.
Reliability Standards Refer to Section 6.2	The development of reliability standards in the state have been a topic of discussion for over a decade. The Commission discussed the development of reliability standards in Docket No. 2011-0206 and a working group developed and proposed the implementation of 10 reliability standards following NERC's standard format. The Companies have reported reliability metrics that reflect some of the standards found in the RSWG report and have established interconnection standards and requirements that reflect other standards found in the RSWG report which have been incorporated into PPAs, RFP procedures, and other tariffs governing interconnection. Other standards from the RSWG report are provided through reported metrics in various dockets. The reliability-related	The Commission should develop a more systematic approach to enforcing reliability standards by revisiting the work completed by the RSWG, via Docket Number 2011-0206, and assess how the reliability standards are currently being implemented or reported, and whether some of the standards originally developed ten years ago should be replaced with new and current standards. The Commission should re-evaluate and propose updated reliability standards based on findings from subsequent proceedings, such as the IGP process. The Commission should also continue to explore cost-effective ways to implement the additional aspects of the HERA scope, including updating and enforcing reliability standards and overseeing system operations.

Interconnection Process Areas	Key Findings	Recommendation
	metrics and interconnection-related requirements have been addressed in the relevant reports and initiatives. Also, new standards are being developed and introduced as industry standards are inherently an evolving process.	

1 Introduction

On June 27, 2022, former Hawaii Governor David Ige signed into law Senate Bill (SB) Number (No.) 2474 as Act 201, Session Laws of Hawaii 2022 (Act 201), which mandates the Hawaii Public Utilities Commission (Commission or HPUC) to engage with a qualified consultant to conduct a study on the accessibility of Hawaii's electric utility grid and procedures for interconnecting generating devices.

The Commission engaged PA Consulting Group, Inc. (PA or the Study Team) to assess the State's interconnection processes, evaluate the accessibility of Hawaii's electric utility grid, and identify the timeliness and costs of interconnection. Moreover, Act 201 mandates the study to include interconnection issues encountered for renewable generation projects greater than five megawatts and any community-based renewable energy (CBRE) generation projects of any megawatt size from investor-owned utilities and utilities that serve counties with a population of more than one hundred thousand. Based on the project requirement mandates of Act 201, the interconnection process review applies to the interconnection requirements established by Hawaiian Electric for renewable and CBRE projects. This study does not include findings about behind-the-meter renewable resources, nor findings pertaining to Kauai Island Utility Cooperative (KIUC).

The Commission has also selected PA to serve as an Independent Engineer (IE) for the Companies' ongoing Stage 3 Request for Proposal (Stage 3 RFP) interconnection process for a three-year period (October 2022 – September 2025).[5] In its role as the IE, PA oversaw various interconnection tasks including, but not limited to, reviewing the Companies' overall interconnection process and technical aspects of the Stage 3 RFP process, developing an interconnection unit-cost guide, and providing insights/advice to the Commission on various interconnection issues. In so doing, PA gained insights into various issues outlined in Act 201.

Due to the overlapping of issues to be analyzed for the study mandated by Act 201 and as the IE, PA and the Commission agreed to conduct the interconnection evaluation in two phases. This report builds on PA's Phase 1 report as well as provides insight into the Companies' administration of its interconnection rules and procedures through stakeholder survey engagement. We discuss this further in Section 3.

1.1 Act 201 Study Scope

The structure of this study follows the directives of Act 201. The IE addressed areas that are both comprehensive and focused on addressing critical aspects of Hawaii's electric utility grid accessibility and interconnection procedures for renewable energy projects. Under Section 1 of Act 201, the Commission is mandated to contract with a qualified consultant to conduct this study.[6] Act 201 encompasses a wide range of requirements and considerations aimed at improving the interconnection process within the State.

First and foremost, the study's scope includes an update regarding the establishment of reliability standards to be overseen by the Commission, ensuring the resilience and stability of Hawaii's electric utility grid and the ability to interconnect with third party renewable energy systems safely and reliably. It delves into identifying the specific interconnection requirements and procedures that will govern the integration of renewable energy projects into Hawaii's electric utility grid. Moreover, it outlines the responsibilities of each entity involved in the interconnection process and determines the reasonableness of the time required for each step, along with assessing the associated costs.

Furthermore, the study's scope extends to an examination of the methodologies used by utilities to calculate interconnection cost, ensuring transparency and fairness in cost allocation. It encompasses a retrospective analysis of the timeliness and costs of interconnection over the past seven years, shedding light on historical trends and potential areas for improvement. Additionally, the study discusses historical challenges faced by the interconnecting entities, and the Companies' documented causes of delays within the RFP Stage 3 period. Overall, the study's scope is designed to provide an evaluation of Hawaii's interconnection process, with a strong emphasis on enhancing transparency and efficiency within the renewable energy sector. The study

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[5] The Stage 3 RFP is a competitive procurement process that allows market participants to bid utility-scale renewable projects in a competitive solicitation to enable the retirement of large capacities of fossil fuel generation. The Commission is responsible for ensuring these competitive procurements are carried out following a fair set of guidelines to achieve shared benefits for the participants in the bidding process and communities that will be impacted by the development of these projects.

[6] Act 201, Section 1(a)

applies to interconnection for renewable energy projects greater than five megawatts and community-based renewable energy generation projects of any size.

As interpreted by the Study Team with coordination with Commission staff, the scope of the interconnection process study includes:

- Compilation of activities relating to establishing additional reliability standards by the Commission;
- An overview of Hawaiian Electric's interconnection requirements and procedures;
- Description of the interconnection administration process and responsible party contributions;
- A presentation and an evaluation addressing the reasonableness of time to interconnect and receive a project's commercial operation date (COD) and associated fees/costs;
- Assessment of the Companies' cost accountability methodology and costs attributed to the developer or the Companies, whether any costs are or can be rate-based or recovered via other mechanisms, cost accounting practices;
- Reporting of the interconnection process activity over the past seven years, including associated interconnection timeliness, delays, successes, and cost information;
- Evaluation of the reasonableness of project management fees;
- Criteria for requiring new or additional interconnection studies;
- Conditions for modifying the interconnection process;
- Confidential incorporation of comments from interconnecting entities;
- Report on the implementation of a Hawaii electric reliability administrator (HERA); and
- Evaluation of PUC's progress in implementing the HERA.

This study specifically provides relevant recommendations on various aspects, including:

- Reliability standards and/or statutory amendments related to the HERA and across Hawaii's electric utility grid and interconnection procedures;
- Interconnection procedures, timelines, cost transparency, and monitoring practices;
- Reporting to the Commission by the Companies and dispute resolution process updates;
- Any regulatory or policy implications that may address interconnection costs, timeline adherence, performance incentives and/or penalties, and other oversight options to enhance the interconnection activities carried out by the Companies; and
- Whether any modifications to the study were required and timelines associated with that modification.

1.2 Statutory Alignment

To meet the mandates stipulated in Act 201, the following reference table provides a mapping to content areas present within the report.

Table 1-1*: Act 201 Directive Mapping*

Act 201 Language	Reference Section in Study
(a) The public utilities commission shall contract with a qualified consultant to conduct a study on the accessibility of Hawaii's electric system and procedures for interconnection to Hawaii's electric system, including but not limited to the timeliness and costs of interconnection.	Section 1
(b) The study shall apply to interconnection for renewable energy projects greater than five megawatts and any community-based renewable energy generation projects of any megawatt size from investor-owned utilities and utilities that serve counties with a population of more than one hundred thousand.	Section 1
(c) The study shall:	
1) Include, but not be limited to, reliability standards to be established by the public utilities commission;	Section 6

Act 201 Language	Reference Section in Study
2) Identify interconnection requirements and procedures for interconnection to the State's electric utility grid;	Sections 2 and 3
3) Describe the interconnection process and who is responsible for each element of the process;	Section 3
4) Determine the reasonableness of time for each element of the interconnection process;	3.1, 3.2
5) Determine the reasonableness of the elements and methodology that utilities utilize to charge for interconnection;	3.4
6) Determine the reasonableness and equity of costs charged to those that interconnect to an electric utility;	3.3
7) Include costs of interconnection by an electric utility for the interconnection of the electric utility's self-build projects;	Sections 2, 3.4, 5.2.3
8) Include reporting and analysis over the previous seven years of the:	Sections 3 and 5
A. Timeliness of the interconnection process from the execution of the power purchase agreement through the interconnection completion, if applicable, or up through the time that the last step is completed; and	3.1, 3.2, 3.3, Section 5
B. Cost of interconnection of renewable energy projects, including:	Section 5
i. The charges to those who interconnected or are in the process of interconnecting to an electric utility;	5.1, 5.2
ii. Any project management fees; and	5.1, 5.2
iii. Any other elements that are relevant in the methodology, including but not limited to the size of the project, the distance to the interconnection point;	Section 5
9) Include documentation of the delays in the interconnection process for stage 1 and stage 2 renewable procurement projects, including the cause of each delay as well as the party responsible for the delay;	5.3
10) Determine whether any elements of interconnection are currently rate-based;	3.6, 7.3
11) Determine the reasonableness of the cost of project management fees assessed by an electric utility to those entities that interconnect to the electric utility;	4.4
12) Determine the reasonableness of requiring new or additional interconnection studies for changes in equipment;	3.1
13) Determine what would constitute a reasonable change to cause a new or extended interconnection process;	3.6
14) Incorporate comments from entities who connect to an electric utility in a confidential manner and be reported anonymously in the study;	Section 4
15) Report on the implementation of a Hawaii electric reliability administrator to be implemented by the public utilities commission;	Section 6

Act 201 Language	Reference Section in Study
16) Evaluate the public utilities commission's progress in the implementation of a Hawaii electric reliability administrator; and	Section 6
17) Recommend statutory amendments to the laws relating to the Hawaii electric reliability administrator.	6.3
(d) The study shall include recommendations on:	Section 7
1) Reliability standards that should be considered and imposed by the public utilities commission on an electric utility;	7.6
2) Interconnection procedures;	7.1, 7.2, 7.3, 7.4, 7.5
3) Reasonable timelines for an electric utility and an entity that interconnects;	7.1, 7.2, 7.3
4) How the public utilities commission can monitor the interconnection process;	7.2
5) Processes, data tools, and reporting requirements by the electric utility;	7.4
6) How interconnection costs can be provided to developers prior to the utility procurement process or how to adjust for changes to the power purchase agreement to reflect interconnection costs;	7.3
7) Mechanisms to be imposed by the public utilities commission and the legislature to improve the timeliness of the interconnection process and the reasonableness of cost;	7.5
8) A process to provide transparency in interconnection costs;	7.2
9) Processes for the public utility commission to oversee and approve the cost and timeliness of interconnection;	7.1
10) Whether interconnection costs should be regulated, tariffed, or rate-based for consistency and transparency;	7.3
11) Whether performance incentives, penalties, or both, should be imposed on an electric utility for timely and cost-effective interconnection;	7.3
12) The reasonable interconnection events that would require modification to this study;	7.2
13) The reasonable timelines for modification caused by an electric utility or an entity that interconnects to the State's electric utility grid;	7.4
14) Resolution processes for interconnection disputes; and	7.5
15) Processes, including administrative, technological, policy, or other related requirements for ensuring effective reliability of the Hawaii electric system and interconnection process.	7.4

1.3 Approach

The Study Team developed the study to align with the directives laid out in Act 201 and with the intention of understanding the process of interconnecting to Hawaiian Electric's utility grid for renewable energy projects.

The study involved information gathering from various sources including Hawaiian Electric, the Commission, and relevant stakeholders. The Study Team determined the appropriate stakeholders to engage in order to gain direct insight from interconnection activities carried out by both the Companies and the developers (also referred to as "bidders", "applicants", or "proposers", depending on the context). The information reviewed included historical interconnection records, regulatory documentation, and participant feedback in fulfilling the directives of the bill.

The Study Team developed its approach to be in alignment with Act 201's directives. Moreover, the Study Team intends for application of the findings and recommendations to be considered for future enhancements to policies, processes, statutes, and procedures. This process ultimately aims to cure deficiencies, encourage efficiencies, and contribute toward a more reliable and equitable energy landscape within the State.

1.3.1 Phases 1 and 2 of the Act 201 Study

The Study Team conducted Phase 1 of the Act 201 Study beginning in October 2022 and completing the Phase 1 report in December 2022, covering a subset of issues included in the Act 201. The Study Team addressed the remaining issues listed in Act 201 in the Phase 2 Report. The Phase 2 Report included updates to the issues covered in the Phase 1 Report. PA intended for the Phase 2 report to be a comprehensive study addressing all issues listed in Act 201.

To achieve the objectives set forth in Act 201, the Study Team applied the schedule conveyed in the table below.

Table 1-2: Schedule for Act 201 Study Execution for Phase II[7]

Deliverable	Key Tasks	Timeline
	Project Kick off	May 2023
	Stakeholder Interview Questionnaire & Finalizing Participant List	May - June 2023
	Information Requests to Hawaiian Electric	July - August 2023
	Stakeholder Interviews	July - August 2023
[X]	**REPORT**: Outline of Phase 2 Report	September 2023
	REPORT: Analysis and Assessment	Sept - Oct 2023
[X]	**REPORT**: Draft Act 201 Phase 2 Report to HPUC	October 2023
	REPORT: Receive the Companies' Comment on Facts	November 2023
[X]	**REPORT**: Final Act 201 Phase 2 Report to PUC	November - December 2023

1.3.2 Engagement with the Commission, Applicants, and the Companies

In Spring 2023, the Study Team convened with the Commission to discuss the schedule and pathway forward to prepare a full Act 201 Report by addressing remaining issues from Phase 1. This included the development of a stakeholder questionnaire, which targets respective aspects of Act 201, and aims to capture an overall sentiment of the interconnection process facilitated by the Companies, from the point of view of the entities who connect to an electric utility. In order to fulfil the statutory directive, the Study Team planned to engage stakeholders to capture perceptions on the administration of the interconnection tariffs, policies, and procedures performed by the Companies. The Study Team performed the confidential primary source interviews, as directed by Act 201, with "entities who connect to an electric utility"[8] to assess the experiences of applicants navigating their projects from bid selection to achieving COD.

The Study Team, with assistance from Commission Staff, pinpointed stakeholders uniquely positioned to provide insights on Hawaii's interconnection process. After securing committed participants, the Study Team formulated questions to elicit general sentiments, observed practices, successes, and challenges with

[7] All items denoted with [X] are formally reported to the Commission.
[8] Act 201 Section 1(c)(14)

renewable generation projects. Stakeholders included IPPs, CBRE representatives, and entities willing to comment on Hawaiian Electric's interconnection tariffs, aligning with Act 201 Section 1(c)(14). To comply, the Commission recognized the importance of incorporating anecdotal experiences and overall sentiments related to the interconnection process. Anonymized reporting preserved participants' ability to comment freely, fostering the sharing of successes and challenges. Adhering to the Commission’s stipulations, the Study Team developed an approach addressing Act 201 directives. Internal portals housed stakeholder materials and sanitized feedback for anonymity and data security. Systematic thematic analysis categorized issues raised by stakeholders, grouping them by frequency of similar insights. This process ensured overall confidentiality and alignment with statutory directives, deriving research from primary source interviews.

The standardized questionnaire categorized major aspects of the interconnection process, ranging from the Interconnection Requirements Study (IRS) and Power Purchase Agreement (PPA) negotiation phases, all the way to achieving COD. The Study Team sought to derive insights from applicants across a range of levels of familiarity and experience with the interconnection process. The Study Team maintained confidentiality throughout the survey period and provided opportunities for higher levels of confidentiality when necessary. Finally, all responses were anonymized ensuring the privacy and confidentiality of the participants and their feedback.

Over the course of the study period, the Study Team established a consistent and iterative dialogue with the Companies, which included activities carried out during the Stage 3 RFP process as well as the Act 201 study. The Study Team initiated targeted inquiries through data requests, which also supported the development of this study. Additionally, the Study Team sought to create a collaborative environment with the Companies and the Commission by way of identification of common themes, real-time experiences, and ensuring accuracy in the Act 201 report.

2 State of Hawaii Electricity Interconnection

The HPUC is the oversight authority regulating the interconnection process. The Companies standardize their administrative processes using individual interconnection tariffs and RFP solicitation provisions. Any process requirements included in these documents are subject to the oversight and approval by the Commission. Additionally, the Commission has set further policy regarding interconnection to the grid through Decision & Orders, Public Hearings, and General Order No. 7, the Standards for Electric Utility Service in the State of Hawaii. General Order No. 7 contains the requirements for electric service within the state and is jurisdictional to all Companies that operate the state electric grid.[9] The guidelines in General Order No. 7 are designed to ensure that the Companies maintain the safety and reliability of the grid in their operations, including the interconnection of new generators, in order to ensure that service is reliable and dependable for all users of Hawaii's transmission system.

Furthermore, there are additional requirements and procedures for construction of high-voltage transmission equipment that are under the Commission's purview; this includes, but is not limited to, equipment used to facilitate the interconnection of generation facilities to the electric utility's transmission grid. Regarding the construction of any high-voltage transmission equipment (particularly 138 kV and above), the Commission has the final determination as to where in the system new equipment shall be constructed, either above or below ground.[10] The Commission is also required to conduct a public hearing whenever the utility plans to build a new high-voltage transmission line "above the surface of the ground through any residential area."[11] This is consistent with the Companies' interconnection tariffs, which outline that overhead line placements are subject to approval from the Commission. One caveat in HRS § 269-27.6 states that the utility does not need Commission approval if the transmission equipment is to be built underground, the entire cost of the underground upgrade is paid for by an entity other than the utility, and the utility provides a report, prior to construction, detailing the project and the funding source.[12]

Currently, the cost of most elements regarding the interconnection process are not rate-based, and instead are the responsibility of the generation facility developers.[13] Specifically, any costs associated with the project's generating facility, as well as most grid upgrade costs are the responsibility of the developer. Per General Order No. 7, the Companies must file their projected capital improvement expenditures with the Commission on an annual basis, as part of the regulations to ensure transparency between the State and the grid operators.[14] The Companies are also required to submit proposed capital expenditures for any single project exceeding $2.5 million in costs, related to plant replacements, and the subsequent interconnection to connect the new facilities to the grid, to the Commission for review in advance of the commencement of construction and/or expenditure.[15] Costs for interconnection facilities deemed necessary for all users of the transmission system, not solely necessary to facilitate the export of generation from a new facility, are the only costs that can be rate-based.[16] The Companies must submit a request to the Commission to rate-base any other costs associated with interconnection.

The cost recovery for self-build projects is subject to approval by the Commission via a 'Request to Recover Capital' spend, per General Order No. 7, if costs are above a certain threshold.[17] The Commission also approves the means of cost recovery, which changed after the Performance-Based Regulation (PBR) framework took effect on June 1, 2021. Under PBR, the Companies may request to recover capital and O&M costs for approved self-build projects via the Exceptional Project Recovery Mechanism (EPRM). The EPRM allows the Companies to adjust the target revenues collected and increase rates to cover project costs during the current multi-year rate period (MRP), subject to Commission approval. Self-build projects are typically

[9] General Order No. 7, Standards for Electric Utility Service In the State of Hawaii, Title VII – Public Utilities Commission, Department of Regulatory Agency, State of Hawaii.
[10] Hawaii Revised Statutes (HRS), §269-27.6.
[11] HRS §269-27.5.
[12] See Hawaii Revised Statutes (HRS), §269-27.6(d), as revised by Act 65, Session law 2021.
[13] Act 201, Section 1 (c)(10)
[14] General Order No. 7, Section 2.3.G.
[15] D&O No. 21002 modified General Order No. 7, Section 2.3.G, requiring that proposed capital expenditures for any single project in excess of $2.5 million or 10 percent of the total plant in service, whichever is less, shall be submitted to the Commission for review.
[16] Hawaiian Electric Rule No. 19 Section C.4
[17] Act 201, Section 1 (c)(7); Also, see footnote 15.

limited to recovering only actual cost for interconnection and cost recovery may be capped, as determined by the Commission. While the Companies have not yet received approval for any self-build projects under the EPRM, cost caps are under consideration for proposed self-build projects. Previously, the Companies could recover capital and O&M costs for self-build projects via the Major Project Interim Recovery (MPIR) mechanism which allowed the Companies to recover costs for large capital projects in between general rate cases (GRC), subject to Commission approval. Under PBR, the MPIR mechanism and GRCs are no longer utilized; however, multiple operational self-build projects being recovered via the MPIR mechanism are legacied into the PBR framework.

3 The Companies’ Interconnection Process Overview

The following section reports on the Companies’ interconnection process and administration of the tariffs, as supported by documentation shared by the Companies and subsequently updated with feedback from the stakeholder engagement phase of the study timeline.

3.1 Companies’ Interconnection Requirements and Timeline

The existing interconnection requirements are covered by a combination of the Companies’ interconnection tariffs, the Companies’ internal policies and practices, Commission Decisions and Orders addressing specific interconnection issues within the State, including General Order No. 7, the RFP under which a project is procured, and the project specific Power Purchase Agreement. General Order No. 7 addresses a broad range of topics related to electric service; however, it does not contain expansive regulations related strictly to interconnection. Instead, General Order No. 7 regulates specific aspects that are related to, or are components of, the interconnection process.

The Companies have a set of tariffs that regulate the interconnection process: Rule No. 19 and Rule No. 14. The tariffs are subject to the Commission’s jurisdiction; therefore, any language updates proposed by the Companies are subject to the Commission’s approval.

Rule No. 19 includes interconnection guidelines and requirements for projects interconnecting to the Companies’ system pursuant to an RFP process. The tariff contains general rules and requirements for independently developed projects to interconnect to the electric utility grid. However, it contains very little information regarding what stakeholders can expect for the interconnection process, or for technical requirements for facilities to interconnect. Additionally, if a provision in Rule No. 19 conflicts with one in a Commission-approved RFP, then the provision of the RFP shall prevail.

Rule No. 14 specifically governs interconnection guidelines and requirements for projects interconnecting at the Distribution level (25 kV and below for Oahu, and 12 kV and below for other islands). The tariff is inclusive of the expectations for independent developers, as well as the Companies, for the entire interconnection process. The tariff also contains detailed technical requirements for facilities to interconnect successfully to the grid.

Table 3-1: Companies’ Interconnection Requirements Related Regulations

Companies	Interconnection Rules
Hawaiian Electric Company, Inc. (for the island of Oahu)	Rule No. 14 Rule No. 19
Maui Electric Company, Ltd. (for the islands of Maui, Molokai, and Lanai)	Rule No. 14 Rule No. 19
Hawaii Electric Light Company, Inc. (for the island of Hawaii)	Rule No. 14 Rule No. 19

Rule No. 14 contains the regulations for service connections, both for load consumption and export of generation, on the utility customer's premises. Regarding the interconnection of generating facilities, Rule No. 14 has policies explaining the interconnection standards specifically for generating facilities connecting to the electric utility's Distribution grid - meaning, any voltage level at 25 kV or below. Additionally, Appendix I of Rule No. 14 explains the process that the Companies must undertake as part of their interconnection process. Rule No. 14 states that the objective of the interconnection process is principally to ensure the safety of the utility system and its customers, maintaining the reliability of the system, and to allow for acceptable power quality that does not impair operation of the system, or any entity who relies on the electric utility's distribution grid. Appendix I contains detailed requirements for the designs of generating facilities (including separate requirements for inverter-based facilities like energy storage), their operation requirements, and protection engineering requirements that facilities must meet in order to successfully interconnect.

Rule No. 19 contains regulations for service connections for facilities looking to interconnect to the electric utility grid pursuant to an RFP process issued by the Companies. The tariffs define the terms used by the Companies to refer to the different aspects of their interconnection processes, for purposes of public education and transparency. Rule No. 19 is considerably less detailed in material compared to the Rule No. 14. Additionally, Rule No. 19 states that the RFP packages, which contain the technical details and requirements for project design and interconnection, will take precedence over Rule No. 19 if a certain provision is in conflict with the RFP. Furthermore, the Companies' Rule No. 19 does not include any detail regarding milestone deadlines for both IPPs and the Companies' responsibilities, engineering requirements for facilities to meet interconnection standards, as well as outlining the processes. Rule No. 19 does outline the initial bid process for the RFP processes; however, the RFP documents, rather than Rule No. 19, go into significantly more detail on requirements for IPP projects to be considered. For all purposes, developers hoping to bid into an RFP and eventually interconnect into the Companies' system do need to adhere to the Rule No. 19 requirements, but they must refer to the applicable RFP documents to find a majority of the meaningful requirements for interconnection at the transmission or sub-transmission level.

Rule No. 19 does include some detail regarding the IRS that the Companies would perform as part of the RFP process, including the FS, as well as information regarding the cost determinations for any required interconnection facilities identified during said FS. The tariffs state that interconnection facilities, "from the point of interconnection to the grid connection point shall be built by the Compan[ies] and paid for by the [developer]"[18]. Like Rule No. 14, Rule No. 19 also clarifies that the document's objectives are to maintain the safety and reliability of the State's electric utility system.

3.1.1 Utility-Scale Interconnection Process

The Companies' interconnection process is a multiphase process that has evolved over the course of multiple Utility-Scale (I.e., Stage 1, Stage 2, and Stage 3) RFPs and CBRE RFPs. It has largely followed the same order, although the Companies have made process improvements to optimize the interconnection timeline and experiences based on the feedback received from external stakeholders, as well as internal team members who support grid interconnection. *Figure 3-1* and *Figure 3-2* provide an overview of the anticipated interconnection process for the Stage 3 RFP project that is currently undertaken by the Companies. *Figure 3-4* provides an overview of CBRE Phase 2 projects.

Project proposals bidding into the Companies' Stage 1 and 2 RFPs first went through the Power Purchase Agreement (PPA) negotiation phase and then sought Commission approval of the executed PPA. While these negotiations and PPA approval were ongoing, the IRS was completed in parallel including review of: the generation facility's technical information, a single line diagram showing the configuration of all electrical components at the site, proof of site exclusivity, and model collection to start the SIS. The data the Companies require from the developers to submit for completion of the IRS, which is similar across the Stage 1, 2, and 3 RFP processes, is outlined in Appendix H of the RFP.[19] Following PPA approval and completion of the IRS, the Companies completed the IRS Amendment to the PPA. In Stage 3, Commission approval will be sought after the IRS is complete rather than after the negotiation, thereby eliminating the need for an IRS Amendment.

Definitions

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

System Impact Study (SIS): A study to evaluate system impacts and specify the facilities, system upgrades, and other requirements for a project to interconnect with the Company's system in a safe and reliable manner.

Facilities Study (FS): A study to develop the interconnection facilities cost and schedule estimate including the cost associated with the design and construction of the Company-Owned Interconnection Facilities.

[18] Rule No. 19, C.3
[19] As an example, see Stage 3 RFP for Hawaii Island, filed November 7, 2022:

Group Study: A method of completing system impact studies for multiple projects at a time; the Companies will simulate the total amount of generation to be exported onto the grid (in MW) of all the projects in the group, in the same simulation run.

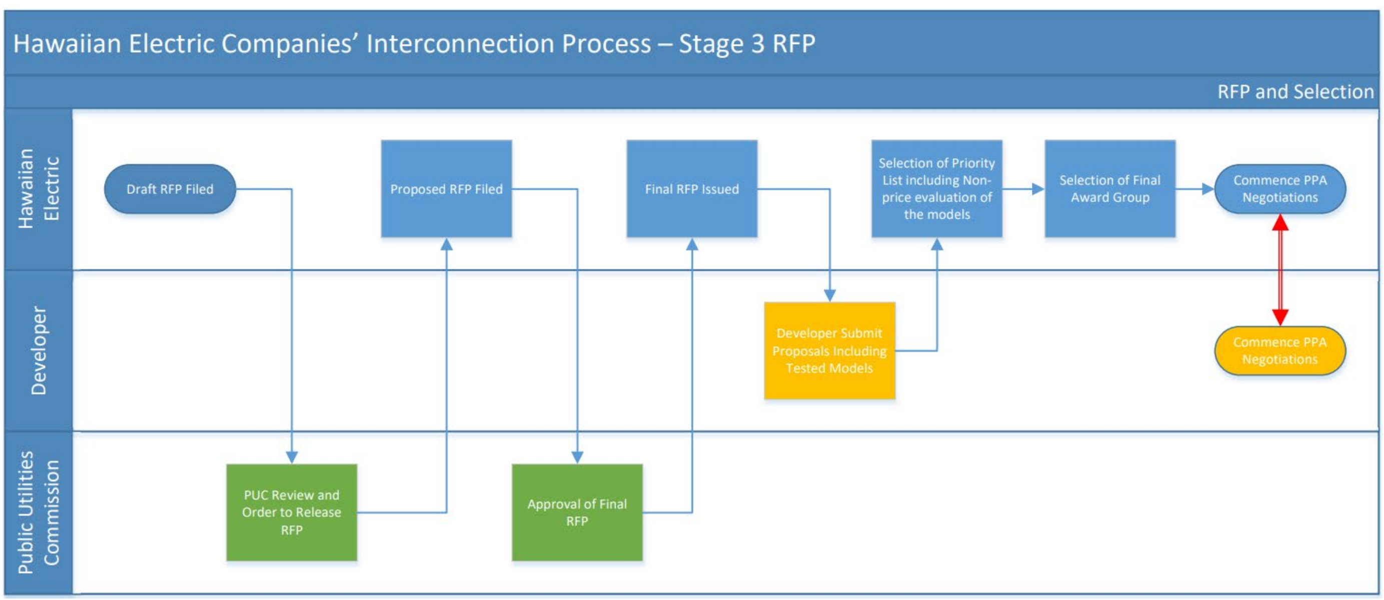
Company-Owned Interconnection Facilities (COIF): Interconnection facilities owned by the Companies. They may be financed either by the Company (whose costs would be reimbursed through a rate-base recovery) or by the developer. This determination will be clarified in Section 1(a) of Attachment G of the project-specific IRS Amendment.

Seller-Owned Interconnection Facilities (SOIF): Interconnection facilities constructed, financed, owned, and maintained by the Seller (developer).

Following the submission and acceptance of the Models and IRS data, the Companies will initiate the formal IRS, including the SIS as well as the FS. The Companies' Interconnection Services team completed the IRS studies, along with their team of consultants, transmission engineers, and planners to run the system impact models. Once the preliminary FS and SIS results are compiled, they are shared with the developer. The Developer will build facilities identified as needed for interconnection, except for any equipment installed in the Company's pre-existing facilities. Once the FS is finalized and the IRS is complete, the Companies will complete the Project Specific Addendum to the PPA to reflect the identified interconnection facilities and upgrades to the grid required for the project to interconnect, the estimated costs for all required facilities to be constructed, and the agreed-upon schedule for construction and commissioning. Furthermore, the Project Specific Addendum must be filed with the Commission for additional review to determine whether to construct the transmission line above or below ground, and Commission approval is necessary unless the line is built underground and funded by an entity other than the utility.[20] Following the construction and commissioning of all interconnection facilities, the Companies will true-up any construction costs and work to settle payments with the developers.

Figure 3-1 and *Figure 3-2* provide an overview of the steps and responsibilities of Hawaiian Electric, the developers, and the Commission during the RFP and Interconnection processes. The steps in *Figure 3-2* commence in parallel with the commencement of PPA negotiations (final step in *Figure 3-1*).

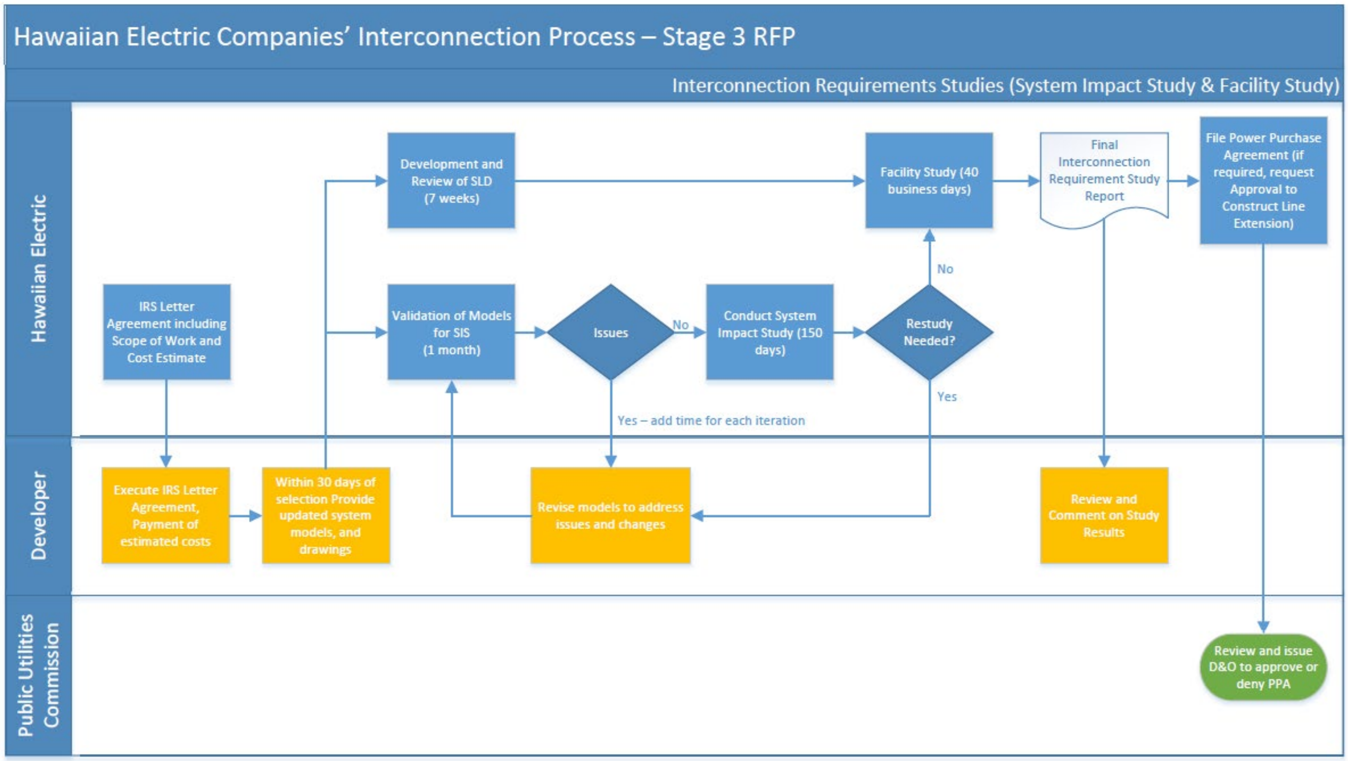
Figure 3-1: The Companies' Stage 3 RFP Interconnection Process During RFP Process[21]



[20] See Hawaii Revised Statutes (HRS), §269-27.6.

[21] Received via Hawaiian Electric in response to PA data request.

Figure 3-2: The Companies' Stage 3 RFP Interconnection Process During Interconnection Studies [22]



For the 'self-build' projects constructed by the Companies, the interconnection process is predominantly identical to the process for IPP projects; however, the PPA negotiation phase does not occur. The self-build projects are managed by separate divisions within the Companies, per the Companies' internal Code of Conduct. The self-build project team's workstream is kept independent to that of the interconnection department. The interconnection department will study self-build projects as they would for an IPP, which is included in a complete IRS, along with a comprehensive FS. Unlike IPP projects, self-build projects will not be subject to negotiations regarding construction of interconnection infrastructure, as the Companies will oversee the work to interconnect their own projects. The self-build projects will still be subject to reporting and approval from the Commission including IRS updates.

3.1.2 Utility-Scale Interconnection Requirements Study Timeline

The interconnection process for renewable projects is a multiphase approach that can be largely grouped into three distinct phases: IRS process, Commission review and final PPA approval, and the construction and commissioning phase. For Stage 1 and 2 RFP projects, the Companies' IRS process was triggered by the acceptance of a developers' project bid via the RFP process and occurred in parallel to the PPA negotiations; however, the IRS was completed after the Commission made its determination on the approval of the PPA, resulting in a subsequent IRS amendment being filed as an addendum to the PPA. In the Stage 3 process, the IRS will be completed prior to the Companies filing their application for approval of the PPA for the project.

The IRS process includes various steps starting from the Company's request of data from developers to start the SIS to multiple steps including performing SIS and FS studies by the Company, negotiation of IRS amendments (known as a Project Specific Addendum for Stage 3) between the Company and the project developers, and the filing of the IRS amendments to the Commission. The Companies have made process improvements to shorten the interconnection timeline in each subsequent RFP. In completing the IRS process, from award of the project to filing of the IRS Amendments, it took an average of 24 months during the Stage 1 RFP projects, and an average of 21 months during the Stage 2 RFP projects.[23] This includes steps 1 through 5 in *Table 3-2* and accounts for items outside of the study itself, such as completing the IRS Amendment. For the Stage 3 RFP projects, the Companies expect to take about 12 months to complete the

[22] Received via Hawaiian Electric in response to PA data request.
[23] The dates attributed to steps 4 and 5 for Stage 1 and 2 RFP projects are actual dates that have received final approval of their IRS results by their respective developers.

IRS process.[24] Moreover, to promote timely completion of the IRS process, the Commission established a performance incentive metric (PIM) creating a financial incentive for the Company to complete the IRS process in under 12 months. The incentive will impose penalties if the IRS process exceeds 12 months for an individual project and Hawaiian Electric can earn rewards by completing its IRS process in less than ten months.[25]

Figure 3-3: IRS Process Timeline during the RFP Process [26]

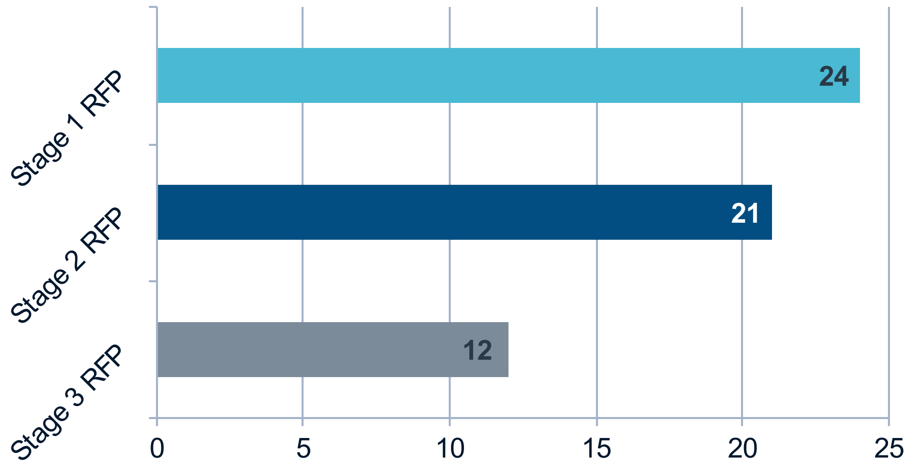


Table 3-2 shows the interconnection timeline of three different RFP interconnection processes administered by the Companies. The Companies use Steps 1 to 5 to manage the IRS process, Step 6 involves a regulatory filing and review by the Commission, and Step 7 includes the construction of the interconnection and generating facilities.

The Companies do not have a standard timeline for the engineering, design, and construction of generation facilities (step 7 of the process) due to the unique scope of work of each project. Various project specific factors impact the construction timeline of the projects. The issues include, but are not limited to, design and permitting considerations, procurement approach, construction means and methods, and commissioning procedures. The timeline reported for Step 7 in the table below for Stage 1 and Stage 2 projects are based on the schedule provided by the project developers during the monthly updates from the developers to the Company.

Table 3-2: Interconnection Related Timeline Established by Companies during the RFP Process

Interconnection Review Process	Companies' Interconnection Process Steps	Stage 1 RFP (months)	Stage 2 RFP (months)	Stage 3 RFP (months)	Responsible Dept
Companies Interconnection Requirements Study (IRS)	Step 1. From Company Request to Receipt of IRS Data and Model Collection to Start SIS	2	2-3[27]	2	Interconnection Services
	Step 1a. From Company Request of Developer Drawings to Completion of Company	2	2	2	Project Initialization [28]

[24] Proposed Schedule filed to the Commission, Docket No. 2017-0352, March 10, 2022.
[25] Order No. 38429, Docket No. 2018-0088, Instituting a Proceeding to Investigate Performance-Based Regulation, issued on June 17, 2022.
[26] The IRS timeline of Stage 1 and Stage 2 RFP projects are based on the projects that have completed IRS process and incorporates steps 1 through 5 of Table 4-2.
[27] For Stage 2 RFP procured projects, the timeline for Step 1 varied depending on projects Guaranteed Commercial Operation (GCOD). For projects with GCOD in 2022, the Developers have thirty days to turn in their models, while projects with a GCOD in 2023 will have sixty days for submission.
[28] Project initialization department coordinates across multiple divisions to input projects and programs for executive approval

	SLD's/Receipt of Developer Drawings				
	Step 2. Start of SIS to SIS Results	5	6[29]	5	Interconnection Services
	Step 2a. Start of Preliminary FS to Preliminary FS Results	2	2	N/A[30]	Project Initialization
	Step 3. Start of Final FS to Acceptance of Final FS	2	2	2	Project Initialization
	Step 4. Presentation of Final IRS Results to Acceptance by Developer	2	1	2	Renewable Acquisition
	Step 4a. Acceptance of IRS to Execution of IRS Amendment	4-10	2-6	2	Renewable Acquisition
	Step 5. Execution of IRS Amendment to Filing of IRS Amendment and Line Approval	1-3	1	1	Renewable Acquisition
Commission Review & Final PPA Approval	Step 6. File IRS Amendment to Receive Approval to Construct Line Extension	5-6	1-3	3-6	Renewable Acquisition
Construction Period	Step 7. Engineering/Design/ Procurement/Construction to Commercial Operations	26-55	38-61	36-72	Project and Program Management
	Total (Steps 1-7) From Request of IRS Data to Commercial Operations	51-89	57-87	55-94	

3.1.3 Interconnection Process Improvements for Stage 3 RFP Process

As part of the Stage 3 RFP, the Companies have altered and are trying to optimize the interconnection process in order to reduce the time required for projects to reach commercial operation, compared to the Stage 1 and 2 RFP projects. The Companies intend to reduce the total process time between the initial collection of the developer's model to the filing of the PPA including Project Specific Addendum with the Commission to a twelve-month period. They have instituted a new model checkout process, better highlighting requirements for developers to ensure that their models are sufficient upon initial submission, to mitigate issues and delays in the SIS phase. The Companies will also provide bidders with pre-highlighted substation requirements, typically identified in the FS, to improve the accuracy of developers' interconnection cost projections and decrease the chance of a project withdrawal due to the unexpected interconnection facility costs. Furthermore, the Companies hope that by completing additional aspects of the SIS and FS in parallel, this would further shorten any delays experienced by a developer initially submitting a deficient facility model. The Companies will also complete the IRS while negotiating the commercial terms of the PPA and submitting the complete PPA and proposal for the project's overhead line, if applicable, for Commission approval.

[29] For Stage 2 RFP projects, the six-month timeframe allocated for Step 2 is to complete the system impact study using a grid following model, which would impact the interconnection facilities.

[30] The Stage 3 RFP process will conduct the PPA negotiation and IRS in parallel so the preliminary FS will not be completed.

3.2 CBRE Interconnection Process

Phase 1

In December 2017, the CBRE framework was adopted under Order No. 35137.[31] The Companies opened the first phase of CBRE in June of 2018. Accompanying the announcement was Order No. 35560[32] filed June 29, 2018, outlining the requirements for the program. The Companies established the interconnection-related requirements for CBRE in Rule No. 26.[33] The interconnection requirements in Rule No. 26 require all facilities to be designed and operate in parallel with the Companies' systems while meeting all applicable standards of the National Electric Code, Institute of Electrical and Electronics Engineers, and the Companies' interconnection standards outlined in Rule No. 14 and Rule No. 19, and subject to any requirements specified in the Interconnection Agreement or the standard form contract. The Phase 1 CBRE interconnection agreement was developed for projects sized at 3 MW or less and did not provide alternative means of interconnection agreements for the various size projects. Overall, the requirements were scattered across the above listed sources and were neither clear nor concise leading to confusion for developers. Of the six initial projects, four are operational and the other two still remain under construction for various reasons explained in Section 5 (as of Q4 2023). Phase 1 CBRE aimed to establish foundational capabilities and gain experiential learning and was somewhat successful in doing so.

Phase 2

Following Phase 1 CBRE, on April 9th, 2020, the Commission issued Order No. 37070[34] in the CBRE Docket No. 2015-0389, instructing the Company to commence Phase 2 of the CBRE program. Phase 2 CBRE is intended to be the long-term continuation of the program with capacity releasing in increments, based on the utilities' resource plans and demand. Additionally, the PUC established seven objectives to significantly increase participation in the program: program capacity, the procurement process, project capacity and distribution, capacity reserved for smaller projects, mechanisms to serve residential and low-to-moderate income (LMI) customers, and special considerations for Molokai and Lanai. Prior to the final launch of the RFPs, the Companies hosted various stakeholder workshops to best understand the needs of developers interested in CBRE development under Order No. 37592.[35] The Companies developed several different RFPs including: LMI CBRE RFPs for Oahu, Maui, and Hawaii Island; Tranche 1 CBRE RFPs for Oahu, Maui, and Hawaii Island; a Molokai CBRE RFP; and a Lanai CBRE RFP, which are all relatively consistent. The Companies clearly invested time and effort to revise the Phase 2 CBRE Program in response to Orders No. 38217[36] and 37954.[37]

Figure 3-4 provides an updated look at the current contract flowchart for CBRE projects. One of the largest changes to note is the inclusion of various tiers of projects, which substantially differ in their interconnection requirements. For Phase 2 CBRE process, the Companies instituted separate interconnection requirements processes via Rule No. 29A. For projects sized less than 250kW AC, the Companies now refer to them as a CBRE Small Project. Interconnection of CBRE Small Projects, including projects with energy storage, shall be subject to the requirements of Rule No. 14H. If an IRS is required, the scope and cost is limited to a "Simplified IRS." A Simplified IRS is limited in scope compared to a standard IRS only including thermal and voltage steady state analyses at the secondary and primary distribution systems, including the service transformer. Projects greater than or equal to 250kW up to 5 MW (Oahu) and 2.5 MW (Hawaii and Maui) are referred to as CBRE Mid-Tier Projects. All projects with sizes above the CBRE Mid-Tier are referred to as CBRE Large Projects.[38]

[31] *Application for Approval to Establish a Rule to Implement a Community-Base Renewable Energy Program and Other Related Matters,* Docket No. 2015-0389 (Oct. 1, 2015)

[32] *Approving the Hawaiian Electric Companies' Community-Based Renewable energy Program Filings,* Docket No. 2015-0389 (Jun. 29, 2018)

[33] Rule No. 26, https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rules/26.pdf

[34] *Commencing Phase 2 of the Community-Based Renewable Energy Program,* Docket No. 2015-0389 (Apr. 9, 2020)

[35] *(1) Developing Recommendations; (2) Addressing Phase 1 Contracts; and (3) Granting the Motion to Withdraw of Renewable Energy Action Coalition of Hawaii, Inc.,* Docket No. 2015-0389 (Jan. 29, 2021)

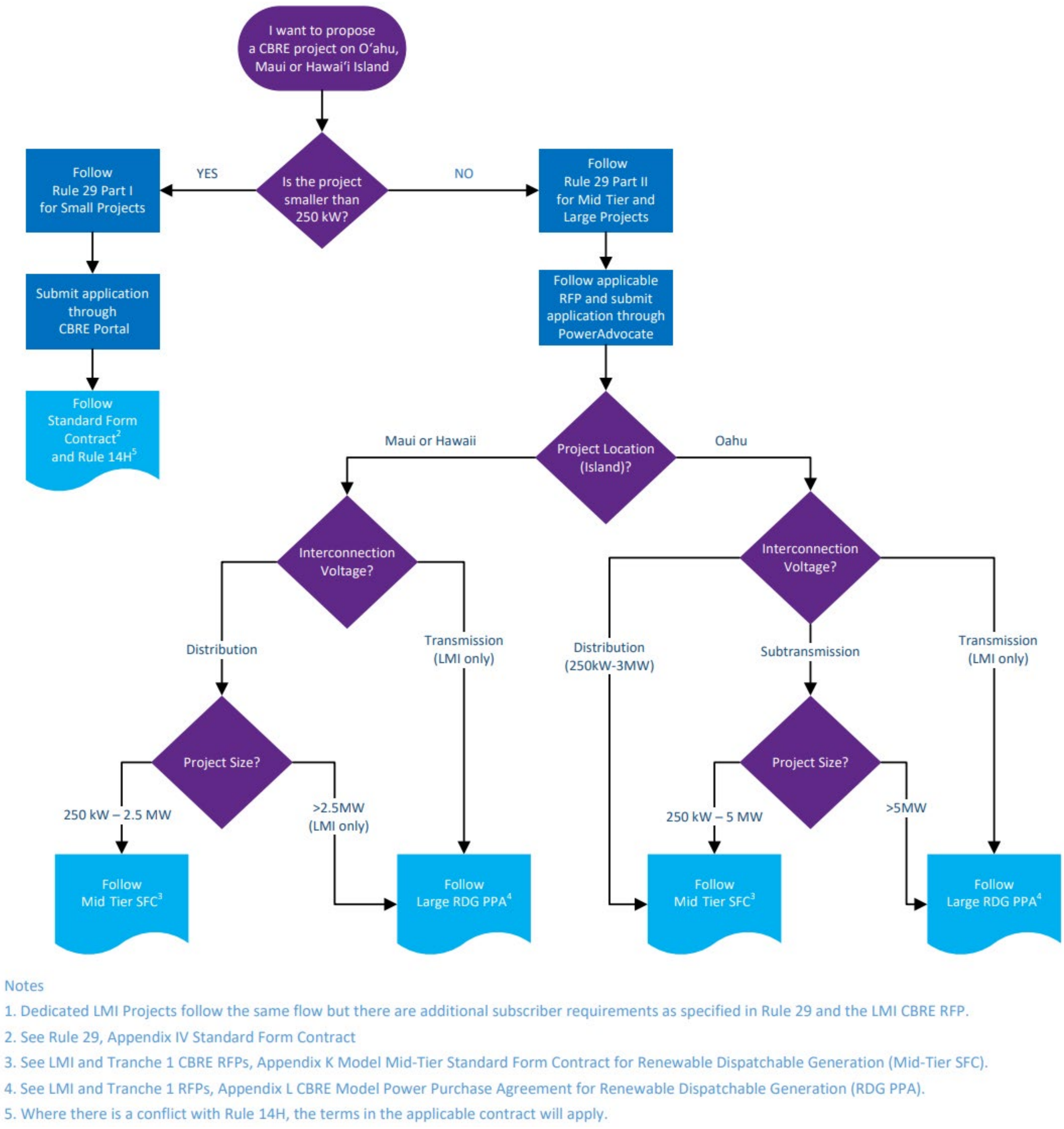
[36] *Approving Phase 2 RPS for Hawaii Island, Maui, and Oahu,* Docket No. 2015-0389 (Feb. 8, 2022)

[37] *Clarifying Order No. 37879,* Docket No. 2015-0389 (Sep. 3, 2021)

[38] *Community Base Renewable Energy Phase 2 Tariff and Appendices, and RPS and Model Contracts for LMI Subscribers and Tranche 1,* Docket No. 2015-0389 (Feb. 2023, 2022)

Interconnection of CBRE Mid-Tier Projects shall be specified in the Power Purchase Agreement for Renewable Dispatchable Generation for CBRE Mid-Tier Projects ("Mid-Tier RDG PPA") and applicable rules and requirements under Rule No. 14H. After the technical review is completed the pre-approved CBRE Mid-Tier RDG PPA is executed and may proceed with development. Interconnection of CBRE Large Projects shall be specified in the Power Purchase Agreement for Renewable Dispatchable Generation for CBRE Large Projects ("Large RDG PPA"). CBRE Large Projects shall negotiate the terms and conditions of the Large RDG PPA that will govern the terms of the project with the Company.[39]

Figure 3-4: CBRE Contract Flowchart for Oahu, Maui, and Hawaii Island including Dedicated Low- and Moderate-Income (LMI) Projects[1, 40]



[39] *Id.*
[40] *Community Based Renewable Energy Phase 2 Tariff and Appendices and RFPS and Model contracts for LMI Subscribers and Tranche 1,* Docket No. 2015-0389 (Feb. 23, 2023)

Additionally, *Figure 3-5* and *Figure 3-6* provide an overview of the CBRE Phase 2 RFP by island and project type.

Figure 3-5: General Overview of CBRE Phase 2 Projects Part C1[41]

Requirement		Small Projects		Mid-Tier & Large Tranche 1 RFPs (includes Moloka'i & Lāna'i)	Mid-Tier & Large LMI RFPs
Project Size	O'ahu	< 250 kW (excludes Moloka'i and Lāna'i)		See Table 2: General Overview of RFP Specifications and Requirements	
	Hawai'i & Maui County				
Available Capacity	O'ahu	30 MW		75 MW	Uncapped
	Hawai'i	7.5 MW		12.5 MW	
	Maui County	Maui: 8.475 MW (7.5 MW + 0.975 MW from Phase 1)		Maui: 12.5 MW Moloka'i: 2.75 MW Lāna'i: 3 MW (CBRE Portion only)	
Credit Rate	O'ahu	$0.15/kWh	Fixed (unless CCRP is triggered)	Competitively Bid	
	Hawai'i	$0.15/kWh			
	Maui County	$0.165/kWh			
Regulatory	Contract Form	Standard Form Contract (SFC)		Mid-Tier SFC or Large RDG PPA	
	Program Rule	Rule 29 Part I		Rule 29 Part I & II	Rule 29 Part I, II & III
SO Project Procurement	Application Process	Online Application		Request for Proposals	
	Where to Apply	CBRE Portal www.communityenergyhawaii.com		PowerAdvocate https://w3.poweradvocate.com	
	Deadline to apply	4 months after Phase 2 begins		See individual RFP timelines	
Subscriber	Account Status	Current Hawaiian Electric account holder			
	Account History	At least 3 months of account history			
	Location	Must be on same island as CBRE project. Proximity-based priority subscriptions offered for first 3 months of enrollments.			
	Selection	Subscriber Organizations (SO) choose their Subscribers			
	Agreement	Between the Subscriber and SO			
	Protections	SO must provide a disclosure checklist; Independent Observer oversees program			
Subscriptions	Size	Based on customer's historical electric usage			
	Transferability	Yes, subscriptions can be transferred to new Subscribers			

41 *Community Based Renewable Energy Phase 2 Tariff and Appendices and RFPS and Model contracts for LMI Subscribers and Tranche 1,* Docket No. 2015-0389 (Feb. 23, 2023)

Figure 3-6: General Overview of CBRE Phase 2 Projects Part 2[42]

Requirement		Small Projects	Mid-Tier & Large Tranche 1 RFPs (includes Molokaʻi & Lānaʻi)	Mid-Tier & Large LMI RFPs
Subscriptions	Buy Back	Yes, with no fees (i.e., if Subscriber moves)		
	Buy More	Yes, but only available subscriptions in their existing CBRE project		
	Minimum	Minimum of 4 individual Subscribers required after a 9-month grace period		
	Minimum Residential	40%		60%
	Maximum Commercial	60%		40%
LMI	Commitment	Optional Commitment		100%
	Subscriber Certifications	Required if committing capacity to Low- and Moderate-Income Subscribers		Required
	Anchor Tenant Certifications	NA		Required if enrolling anchor tenant
Fees and Cost Responsibilities	Application Fee	$250	Oʻahu, Maui & Hawaiʻi : $2,000-$10,000 Molokaʻi: $1,000-$2,000 Lānaʻi : $5,000	$1,000 -$5,000
	Program Administration Fee	$5/kW AC NTE $1k annually	$5/kW AC Mid-Tier: NTE $5,000 annually Large: NTE $10,000 annually	Waived
	Interconnection Cost Responsibility	Subscriber Organization	See Appendix H of the respective RFP	

3.3 Interconnection Costs Accounting

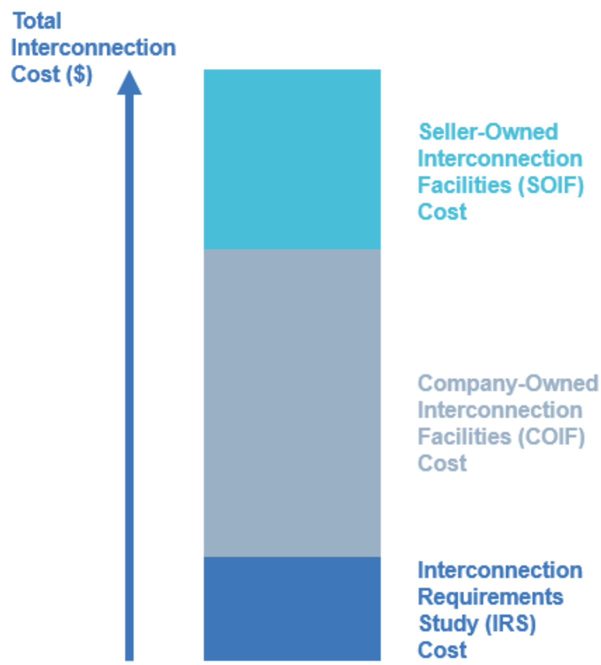
This section discusses Companies' interconnection cost accounting process.

3.3.1 Interconnection Cost and True-up

The interconnection cost of each project is determined by facilities identified in the FS that are necessary to interconnect the project to Hawaii's electric utility grid. Figure 3-7 provides an illustration of total interconnection cost which includes three major cost components: the IRS costs, COIF costs, and SOIF costs. For IPP built projects, COIFs are paid for by non-utility entities– consistent with the utility's standards and requirements. SOIFs are paid for by non-utility entities, but typically are not disclosed to the utility. Therefore, the Companies are only able to report actual COIF costs for work the Companies performed associated with IPP built projects.

[42] *Community Based Renewable Energy Phase 2 Tariff and Appendices and RFPS and Model contracts for LMI Subscribers and Tranche 1,* Docket No. 2015-0389 (Feb. 23, 2023)

Figure 3-7: Illustrative Example of Interconnection Costs



Before the start of the IRS process, developers are required to submit two payments to the Companies. The first payment is used to complete the SIS and FS which typically ranges from $140,000 to $220,000. The second payment is used to complete the IRS Amendment after completion of the IRS as part of the interconnection process. Any remaining funds are rolled into the amounts due for the COIF. Both fees are subject to a true-up following the completion of the IRS and commercial operation of the project. Certain internal departments, including engineers and consultants contracted by the Companies to assist with the interconnection studies, charge time for their efforts to these fees, whereas other salaries, such as the Energy Contract Managers' salaries, are rate-based.

Following feedback from the Stage 1 and 2 RFPs, the Companies have included a publicly-accessible unit cost guide for all transmission-level electric equipment that could be used in constructing interconnection facilities – this unit cost guide is included in Appendix H of the Stage 3 RFP documents. The Companies believe that by making the unit cost guide publicly available at the start of the process, developers can have more informed bids, based on the size of their facilities, as well as where they intend to interconnect onto the grid. For self-build projects, the Companies use the same unit cost guide found in Appendix H of the Stage 3 RFP to price out their facilities.

Following the finalization of the IRS, developers who do not accept the costs for upgrades quoted in the FS have the ability to withdraw their project from the process. The RFPs explicitly state that IPPs are responsible for the actual final interconnection costs, whether or not such costs exceed the interconnection costs estimated in the proposal, and no adjustments are allowed to the proposed price if actual costs exceed the amounts proposed.[43, 44] All costs for interconnection facilities for IPPs are subject to true-ups following the commercial operation of the project.

[43] See Section 2.3.4 of Stage 3 RFP for Hawaii Island, Section 2.3.5 of Stage 1 and 2 RFPs.

[44] Hawaiian Electric recently allowed multiple IPPs to renegotiate the pricing for their projects and subsequently submitted executed PPA amendments to the Commission for review. The Companies state that the requests for amendments were due to increased costs and delays caused by the COVID-19 global pandemic and resulting supply chain crisis and were not due to changes in the interconnection costs determined as a result of the IRS. The Commission has reviewed such requests on a case-by-case basis, weighing the implications of the updated pricing proposals on the competitive bidding process, recognizing that certain factors related to the supply chain interruptions from the global pandemic which resulted in equipment cost increases were out of the developers' control.

3.3.2 Interconnection Cost – Commission Oversight

Regardless of cost responsibility, all foreseen interconnection costs are ultimately borne by the ratepayers. For the components of the interconnection costs that are directly paid for by the utility, these costs will be paid for through one of the cost recovery mechanisms available to the utility, subject to Commission approval based on the amount and the cost category. For the components of the interconnection costs that are paid for by non-utility entities, the costs that are foreseen are included in the price of the contract that the utility pays to the non-utility entity. These contract payments are then passed through to the ratepayers under the cost recovery mechanism for power purchases, subject to Commission approval. When interconnection costs are unforeseen and unaccounted for in the contract price, the non-utility entity must absorb these additional costs. The contracts do not allow for price modifications in the event that the actual interconnection costs exceed the estimated costs; however, non-utility entities may seek to increase their contract price via an amendment that must be negotiated with the utility and approved by the Commission.

For the costs paid for by the non-utility entities, the Commission has less oversight and less ability to impose cost containment measures as it does over the utility. As a result, the Commission has been evaluating policy changes to transfer certain cost responsibilities to the utility. While the impact to the ratepayer would at first glance be the same if the utility or the non-utility entity paid for these costs, under the PBR framework and increased scrutiny by the Commission, there may be greater potential for cost containment and potential cost savings from transferring certain costs to the utility. It is possible that developers may be able to negotiate lower costs for equipment given their market influence; however, the utility may also be able to use bulk purchasing to negotiate lower costs. The Commission intends to make policy decisions in the best interest of the ratepayers while ensuring that the utility is allocating costs prudently to preserve reliability of the system.

3.4 Interconnection Process Reporting

3.4.1 Hawaiian Electric's Tools, Processes, and Reporting for the Interconnection Process

At present, the Companies do not maintain and or utilize any internal databases such as file-hosting portals for shared drive access, which may generate automated notifications or track milestones inherently related to the timeliness of completion of the different interconnection process steps. Instead, they rely on official dates of notices related to the completion of each stage of interconnection process (by the Companies), and they account for the different process step completion dates within the master schedule provided in their monthly reports to the Commission for each project.[45] They also account for milestone completion dates in monthly emails that they send to all internal and external stakeholders for each project; for instance, the completion date of the FS is tracked by two emails sent out by internal teams within the Companies, one at the commencement of the study and the other upon completion, and the dates of each email are used to track compliance with the FS's 40-business day requirement. The Companies rely on the monthly reports and emails sent to developers and the Commission as their records, instead of using a database to maintain milestone information. The interconnection team(s) within the Companies also use spreadsheets to track the work done for each interconnection project and send weekly updates for each project to executives. Metrics for cost and timeliness of interconnection of IPPs are reported on the Company's website. These reports include costs to perform the IRS, Company costs for COIF, time from presentation of Final IRS Results to commercial operations and actual vs. estimated costs for the interconnection.[46]

Based on follow up discussions with the Companies, we understand that the Companies are working on developing a centralized interconnection website to offer insights and transparency to stakeholders. The website is intended to host materials including requirements, interconnection process and issues that can cause delays in the interconnection process. Companies are targeting the interconnection website to be publicly available by end of 2023.

[45] For example, see Exhibit 1, November 2022 Report, Docket No. 2021-0024, Filed November 23, 2022.
[46] Available at: [Interconnection Experience | Hawaiian Electric]

3.4.2 Interconnection Process – Commission Mandated Reporting and Monitoring

The Commission monitors the interconnection process through docketed proceedings, as well as through multiple entities hired to provide oversight on the RFP and interconnection processes. The docketed proceedings through which the Commission monitors the interconnection process include:

- RFP Dockets (e.g., Docket No. 2017-0352[47] for Stages 1, 2, and 3 RFPs and Docket No. 2015-0389[48] for CBRE RFPs) – These dockets are used to receive filings and letters related to utility procurements for new renewable energy projects. The utility files its draft and final RFPs, the Consumer Advocate files information requests and position statements, and the Commission files information requests, decisions, and orders pursuant to the RFP filings. There are no other parties to this docket; however, members of the public and other organizations have historically filed public comments to this docket related to RFP and interconnection topics.
- Interconnection Docket (Docket No. 2021-0024[49]) – This docket was established in 2021 to launch an investigation into the interconnection practices of the utility, which included multiple status conferences with the utility and non-utility entities that had experience in the interconnection process. Currently, the utility submits monthly reports to this docket providing (1) status updates on all projects currently in the interconnection process, (2) reliability metrics for the utility's system, and (3) compliance reports detailing the generation sources on the utility's system.
- PPA Dockets –Individual dockets are opened upon the filing of application for power purchase agreements between the utility and non-utility entities and include, among other project-specific documents, interconnection-related specifics for individual projects. These dockets also include project-specific interconnection-related requests for Commission approval.
- PBR Docket (2018-0088[50]) – The Commission established a performance incentive mechanism and multiple tracking metrics related to interconnection timeliness and costs as part of the PBR Framework and continues to use this docket to monitor performance and progress.

The Commission intends to continue to use its docketed proceedings for future RFPs and PPAs. Also, based on the success of monitoring the projects from the Stage 1 and 2 RFPs and CBRE RFPs, the Commission intends to continue to utilize a docket to collect monthly status updates for all projects. The monthly project reporting is particularly helpful to monitor the development status of the energy projects.

Following the Commission's Status Conference held in March of 2021, the Companies provide the Commission with monthly updates on the status of all RFP projects currently under development (Stage 1 and 2), as well as projects associated with the CBRE shared solar program. The Commission requires the Companies to also track delay-related costs in commercial operations of all Stage 1 and 2 RFP projects and CBRE projects, per the Commission's order No. 37752.[51] The reports also now contain information regarding the project construction schedules, maintenance information, and updates to projects that have not yet reached commercial operation, following a request sent by the Commission to the Companies in February 2022. The reports are very detailed. Updates from previous reports are denoted in redlined edits to highlight tracking of new information. Information included in the reports include:

- The Guaranteed Commercial Operations Date (GCOD);
- The gross nameplate rating of the facility, the generating technology(ies);

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[47] *To Institute a Proceeding Relating to a Competitive Bidding Process to Acquire Dispatchable and Renewable Generation,* Docket No. 2017-0352 (Oct. 6, 2017)

[48] *Application for Approval to Establish a Rule to Implement a Community-Based Renewable Energy Program, and Other Related Matters*, Docket. No 2015-0389 (Oct. 1, 2015)

[49] *Opening a Proceeding to Review Hawaiian Electric's Interconnection Process and Transition Plans for Retirement of Fossil Fuel Power Plants,* Docket. No 2021-0024 (Feb. 11, 2021)

[50] *Institute a Proceeding to Investigate Performance-Based Regulations,* Docket No. 2018-0088 (Apr. 18, 2018)

[51] The Order 37752 was filed with the Commission on April 27, 2021. However, the Companies filed a dispute on May 7, 2021, and Commission responded in Order No. 37792, clarifying its directive to track delay-related costs but not, at the time, record or impose any penalties related to such costs.

- The RFP Stage;
- Status on the PPA procurement negotiations;
- Status on the SIS – including any updates to the facility that would trigger a re-study;
- Status on the FS;
- Status on the engineering, design, and construction of the Generation Facility and any Interconnection Facilities;
- Status of permits for the construction of the Generation Facility and any Interconnection Facilities;
- Status on the Commissioning test of the Generation Facility and any Interconnection Facilities.

The reports also use a three-colored system to track the status of the overall project, and whether it is on target to meet the GCOD: green denotes that the project is currently on track to meet the GCOD; yellow denotes that the project is at risk for missing its GCOD; red denotes that the project is expected to miss its GCOD. For each phase, the report includes status on the current work being done, the expected or actual date of completion, as well as the responsible party for each phase, particularly to highlight any delays that could be caused by either the Companies or the Facility owner. The interconnection timeline and status of the renewable projects under construction is discussed in Section 4 of the report.

The Commission also utilizes third party experts to assist in the monitoring of the RFP and interconnection processes. These entities include the Independent Observer and Independent Engineer, who are hired for specific RFPs. These entities aid the Commission in directly communicating with the utility and non-utility entities, reviewing interconnection and RFP materials, and advising the Commission on matters related to RFPs and interconnection. Commission staff teams assigned to the RFP and interconnection dockets actively manage the Independent Observers and Independent Engineers to keep apprised of issues and direct these entities to investigate specific matters.

3.5 Interconnection-Related Dispute Resolution Process (IDRP)

Following the recommendation from the Act 201 Phase 1 report, the Commission directed the IE to establish an interconnection-related dispute resolution process to address any potential disputes between the Companies and project developers. As a result, the IE helped the Commission in establishing the IDRP. Specifically, the IDRP framework is designed to consider any interconnection-related dispute[52], within the context of the current competitive bidding process – the Stage 3 RFP process – that arises at any time between selection of priority list projects to execution of the PPA[53]. The IDRP covers disputes between the Companies and a developer regarding the study considerations of interconnection to a proposed project [including both the system impact study (SIS) and/or facilities study (FS)], or in relation to the facility acceptance (commissioning) and control systems acceptance testing. Issues outside of interconnected are covered by a formal dispute resolution process which was pre-existing.

The IDRP framework contains different resolution levels through which mediation of disputes will be facilitated, and assignment of responsibilities to the appropriate parties, whether they be: the IE; the Companies; the Proposers; or the PUC. The proposed IDRP framework was established on April 18, 2023, by Order No. 39163.[54] The framework is included in Appendix A.

Interconnection Dispute Resolution Process Overview

In the Stage 1 and 2 RFP projects, the Companies did not have a specific dispute resolution process for addressing interconnection issues. For the projects solicited via the RFP processes, the Companies rely on a standard dispute resolution process for disputes that arise prior to execution of the PPA. The Stage 3 RFP outlines the dispute resolution process, as well as the Commission's expectations on the subject, established in the competitive bidding framework (Section 1.10). If a dispute is raised by a developer, that party is encouraged to work with the Companies to reach a resolution before raising the matter with the Commission. An Independent Observer is to be present at an initial meeting between the disputer and the Companies and

[52] The IDRP framework does not include additional scope that may be the topic of a dispute between the Companies and developers, such as contractual issues related to power purchase agreements (PPAs), or interpretations of the regulatory framework (unless it specifically pertains to an interconnection requirement).
[53] Once a PPA is executed, disputes should be resolved based on the PPA dispute resolution terms.
[54] *Establishing the Interconnection Dispute Resolution Process for the Stage 3 Requests for Proposals,* Docket No. 2017-0352 (Apr. 18, 2023).

will act as a mediator between the two parties; the Independent Observer will not have decision-making authority and can only advise the parties on a potential resolution.

Additionally, if the dispute is not resolved within twenty days after the initial meeting, the two parties have the option to procure another third-party firm to attempt mediation independent of the appointed observer, and the two parties will be required to split the cost. If this fails to produce a resolution acceptable to both parties within sixty days of the initial meeting, then the disputer will be allowed to raise their issue(s) with the Commission.[55] If a dispute is escalated further, the Commission will attempt to resolve the issue within thirty days of notice – however, the disputer currently has no right to a hearing or any appeal under this process.[56] Finally, if a bidder submits a dispute outside the process described in the Commission's framework or Section 1.10 of the Stage 3 RFP, then the dispute will be dismissed with prejudice, and the bidder will be held responsible for all attorney fees and costs incurred by both the Commission and the Companies.[57] For disputes that arise after PPA execution, the dispute resolution provisions set forth in the PPA govern any disputes that may arise.[58]

For the Stage 3 RFP process, the Commission has also appointed an IE to oversee various interconnection tasks including, but not limited to, reviewing the Companies' overall interconnection process and technical aspects of the RFP process. The IE is also tasked with assisting the Commission in establishing a dispute resolution process for interconnection-related issues.

3.6 Interconnection Process and Cost Enhancements for Consideration

The following findings for interconnection process improvements are based on the Study Team's understanding of Hawaiian Electric's interconnection process via preparation of the Act 201 report and serving in the IE role for Hawaiian Electric's Stage 3 RFP Process.

Moreover, the IE also assisted the Commission in a separate review of the current and past RFP and interconnection procedures and developed several areas of improvement for the Commission to consider in its review of the forthcoming RFPs in 2024. In particular, the IE directly provided its insights and findings regarding interconnection cost and technical data requirements of the RFP process. Multiple relevant areas of improvement are included as findings and recommendations in this report.

Consider policy changes to incorporate accurate interconnection cost in PPA

The Study Team's recommendations for future interconnection cost changes are based on review of prior interconnection cost work, discussions with stakeholders, and serving in the IE role for Hawaiian Electric's Stage 3 RFP Process. The Companies' method for studying project interconnection – by identifying potential impacts to the grid and determining upgrades needed to ensure safe interconnection – leaves many unknowns in the current RFP process that make it difficult to determine accurate interconnection costs and to lead fair PPA negotiations.[59] We recommend multiple enhancements that may improve the accuracy of interconnection cost in the PPA prices.

First, The Commission could allow the incorporation of interconnection costs in power purchase agreement (PPA) prices into procurement negotiations following the SIS. By moving the final PPA negotiations until after the completion of the system impact and facilities studies, bidders would have more accurate information to incorporate into their final bid price. Moving the final PPA execution (or allowing for a re-negotiation) after the completion of both the system impact and facilities studies will also ensure that ratepayers bear the actual interconnection cost, for both COIF and SOIF.

[55] Docket No 2003-0372, Order 23121, Issued December 8, 2006. Also included as Appendix C in Stage 3 RFP process.
[56] Docket No 2003-0372, Order 23121, Issued December 8, 2006. Also included as Appendix C in Stage 3 RFP process.
[57] See Section 1.10.6 from Stage 3 RFP for Hawaii Island.
[58] The Companies state that for the post-PPA process, the dispute resolution process is developed on case-by-case basis, but usually follows a consistent structure. Typically, when a dispute arises in post-PPA phase, the first step calls for a management meeting followed by mediation, and finally litigation for any unresolved disputes in the earlier phase. The Companies also mentioned that in some post-PPA dispute resolution processes, the agreed PPA terms could involve a review by an IE mutually selected by the parties, distinct from the IE that was recently hired by the Commission to serve in the Stage 3 RFP process.
[59] In Federal Energy Regulatory Commission (FERC) jurisdictional wholesale regions of the US and Electric Reliability Council of Texas (ERCOT), interconnection is separate from power procurement largely due to federal insider trading rules.

Alternatively, the interconnection process could be separated from the RFP process, or developers could have the opportunity to amend and renegotiate PPAs to reflect the trued-up interconnection costs – this would allow PPAs to reflect the accurate interconnection costs.

Provide additional information to the bidders in the pre-bid process

In the IE role, PA reviewed Hawaiian Electric's evaluation of the Stage 3 RFP bids data and process which included validations, resolving any technical data deficiencies, and disqualifications of the bids. PA also monitored discussions between Hawaiian Electric and potential bidders. We observed it is beneficial for bidders to have more information on Hawaiian Electric's grid, studies and bid evaluation process. The Companies could develop a one-stop place for bidders to understand the interconnection process. This could include various information including interconnection requirements, bid evaluation methods and criteria, dispute resolution processes, and status on projects that are undergoing the interconnection process. We understand that the Company is developing a website to host all interconnection process to be fully functional by end of 2023. The Study Team fully supports this initiative, and we believe that this will provide further clarity to the developers on Hawaiian Electric's interconnection process.

The Study Team also believes that there are benefits in providing standard information of the specific substation or Point of Interconnection (POI) during the pre-bid process. Providing this information in a templatized pre-application report would help bidders to obtain a basic understanding of the potential costs in construction, operation, and overall investment risks in interconnection to the POI.[60]

The developers that the Study Team interviewed also shared that Companies should provide details about the system design, historical and planned system upgrades, and other information that would assist applicants in determining a right-sized project. The interviewees acknowledged that much of this is provided in the later stages of the RFP process and post selection activities. However, interviewees shared similar sentiments in that there are data characteristics that are integral to sizing their system's capacity for delivery that would minimize interconnection upgrade costs and make their projects overall cost effective.

Whether it is in relation to existing distribution studies or planned upgrades that are otherwise found in other regulatory filings or company business plans, developers suggest that the RFP incorporate the following information:

- Existing tariff, regulatory, and interconnection rules and procedures
- Approved protection devices and scheme characteristics
- Providing POI information such as projected load and generation, maximum short-circuit levels
- Equipment costs and sizing anticipated with potential upgrades
- Distributed Generation site metering infrastructure and communication requirements
- Company procedures, maintenance schedules, outage data, operational constraints, and any other practices notable to managing the voltage and capacity limits

Using a multi-step approach in collecting interconnection related data

The Study Team understands that as a part of Stage 3 RFP process improvements, Hawaiian Electric required all bids to include interconnection and technical related data with the initial bid submission. The Companies requested numerous technical data related with interconnection. These are outlined in Appendix B Attachment 2b of the Stage 3 RFP document.[61] This process is set up as a single step which collects all possible technical information to not only perform interconnection studies, but also to design, procure equipment and fully construct and operate the plant from all bidders. In the IE role, PA observed that many of the technical data requested as a part of bid submission are not necessary to perform initial technical studies during the bid

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[60] The information on standard pre-application report could include, but not limited to, description of POI, POI capacity, hardware information at POI, and grid related information such as grid performance, recent planning studies, and planned expansion and generation in the area.

[61] For example, please refer Appendix B, Attachment 2a of Hawaii Island RFP via this source: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/selling_power_to_the_utility/competitive_bidding/20230228_hawaii_stage_3/20230322_appx_b_proposers_resp_pkg.pdf

evaluation process. These include design information and equipment performance data. Therefore, the timeline for requesting some of the technical data can be delayed.

The developers interviewed[62] during the stakeholder engagement process shared that providing the requested information early in the RFP process was challenging and onerous on the applicant. It was communicated that the modeling requirements during the RFP process are unreasonable and lead to a lot of wasted time as iterations are ultimately required. Deferring the submission date for some of these data would foster a healthy competitive environment, increase participation, and allow bidders to focus on preparing optimal bid packages. The developers also recommend the Commission balance rigor with efficiency when designing the RFP process. By simplifying the initial requirements this enables a truly competitive outcome for the bid selection process and allows for more unique clarifications after the shortlist is determined.

The Study Team recommends a multi-step approach where data requests are split across the following deadlines: at bid submission and at final award, and prior to the start of IRS process. The Companies could also postpone requesting equipment specific, design specific, construction specific and operation specific information in the later stage, such as at the start of the construction phase. We recommend sequencing data collection such that only the absolute minimum required data is collected first and more detailed information is collected as the winning bid proceeds to construction phase.

The Study Team believes that this “multi-step” approach will streamline and enhance the Companies’ interconnection process and provide value by reducing the cost of bid preparations encouraging submission of more bids in future RFPs. It will also reduce efforts necessary from the Companies’ staff when reviewing and validating highly detailed information that are not utilized until the IRS process. This multi-step approach will also reduce the number of deficiencies and enable the Companies to shorten timelines from bid to award of an Interconnection Agreement.

[62] Section 4 discusses stakeholder feedback in detail.

4 Stakeholder Insights on Interconnection Process

The following section outlines categorical responses from stakeholder interviews that the Study Team conducted as a part of the Act 201 Study. The stakeholders include a group of project developers that have interconnection process experience with the Companies. Continuing with this study's directives to incorporate anonymized feedback from stakeholders, the Study Team presents the following section, which captures general experiences into thematic analysis, encapsulating the intricacies of unique project experiences as well as common concerns, successes, and challenges. The compilation of these categories and corresponding insights were based on the study components outlined in Act 201, as presented in the interview questionnaire in Appendix A.2.

Stakeholder Engagement Process

In May 2023, the Study Team invited 15 stakeholders to participate in guided interviews, consisting of Stage 1 and 2 Utility-Scale project developers and CBRE Phase 1 developers. From June to August 2023, the Study Team interviewed a total of nine stakeholders including five CBRE stakeholders, four Utility-Scale developers, and one Engineering, Procurement, and Construction (EPC) contractor in support of a Utility-Scale project. The conducted interviews held a duration from one to two hours depending on the level of detail in recalling prior experiences. The interview followed a pre-shared questions list to maintain consistency and eliminate variability that may arise from modularity in question design. Further, the Study Team designed the process to reduce bias from wording or order of questions, eliminated follow on inquiries, and utilized the interest topics and directives ordered from Act 201.

To steer the direction of conversational responses, a standardized interview form presented a series of questions while preserving anonymity. The intention of these conducted surveys is to gather experiences, insights, successes, and challenges to present an overall depiction of how the Companies are administering their interconnection policies and procedures. The exploration into sentiments experienced by developers interconnecting approved projects to the grid elucidates the realities underpinning the interconnection process thereby furnishing critical insights for prospective enhancements or identifying instrumental achievements in streamlined activities.

The Study Team did not provide an interview questionnaire for the Companies. The Study Team, rather, focused on direct data request correspondence with the Companies to assess the interconnection process, associated data and timelines, and status of the projects that are under IRS and interconnection process.

The Study Team developed the themes discussed below based on the information shared by developers, including the general sentiments towards and specific experiences with Hawaiian Electric's interconnection process. As a result, this section highlights the realities of the grid integration process from the project developer perspective and paints the landscape both generally and anecdotally. This approach enables the voices of participants in influencing future requirements and/or policy changes by shedding light on the complexities, nuances, and areas of potential enhancements. The Study Team believes that this transparency into the process will further the objectives of a more streamlined, fair, and transparent practice for interconnecting renewable resources to the grid.

4.1 Interconnection Requirements

Survey Questions

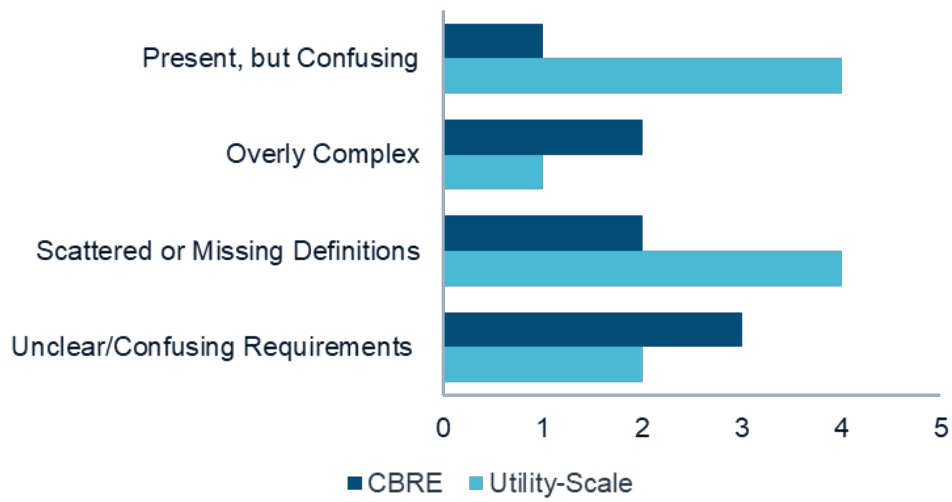
- Which information sources did you review to understand HECO's interconnection requirements?
- From your perspective, are interconnection requirements clearly laid out in these information sources? If not, please discuss what specific areas of these information sources could be expanded?

Survey Feedback Summary

Stakeholders communicated the complexity and uncertainties present in the Companies' interconnection requirements to the Study Team. Although the information is available to developers through the RFP process, codified tariffs and the interconnection agreements, challenges have arisen over the course of the Stage 1, 2 and 3 RFP processes. While the tariffs provide clear requirements, aspects of the RFP have been altered after each solicitation process, which supersede the tariff. Stakeholders reported that this can cause confusion when navigating the upcoming RFP processes. Moreover, incongruent depictions of requirements, processes, and specifications can cause delays.

Stakeholders understand that changes in requirements and processes can be necessary due to the needs and specifications of Hawaiian Electric's system; however, a more comprehensive approach to updating technical requirements within each RFP phase may streamline the IRS process for awarded projects. *Figure 4-1* describes the overall perceptions of interconnection requirements for Utility-Scale and CBRE projects.

Figure 4-1: Interconnection Requirements – Feedback



Study Team's Views: Recognizing the challenges inherent when updating procedures and requirements, the Study Team acknowledges the intricacies in aligning technical characteristics with system capacity needs, specifications, and availability. Predictability is a necessary feature of the interconnection process when facing evolving industry standards for equipment and complex utility grid designs. For example, legislatures tasked regulators in similar jurisdictions, such as California, pursue evaluations to reveal potential gaps, successes, and challenges (Ting, 2016. Assembly Bill 2861).

Such evaluations encourage streamlining interconnection timelines, standardizing requirements thereby facilitating a more streamlined process for integrating complex systems such as microgrids. These initiatives invite the integration of sophisticated controls systems, precise communication schemes, and also challenge grid infrastructure through islanding capabilities and voltage frequencies, regulation, and other real-time monitoring adaptabilities. By exploring methods to more effectively communicate and tailor requirements for each project classification, utilities can not only expedite the interconnection process but also equip both seasoned and unfamiliar developers in navigating the evolving landscape of grid integration. A clarified and simplified approach, therefore, not only addresses the immediate technical and regulatory challenges but also sets a precedent for a more agile, responsive, and informed interconnection framework.

Stakeholders reported that the Companies' interconnection documents are complex and require time to sift through technical characteristics, restrictions, performance requirements and other elements, which may lead to a delay in the design process. Respondents often echoed the sentiment that navigable flow of the requirements would be a beneficial enhancement when updating guidelines for the next RFP process. This can be achieved through logical flow chart depictions with reference remarks to applicable tariff language, technical requirements, and other policies and conditions. Stakeholders reported difficulty keeping up with the updates that are made to subsequent RFPs which hinder stakeholders' understanding of the Companies' interconnection requirements. These difficulties have caused unnecessary cost increases, timeline delays, and lost revenue.

4.2 IRS Timeline Summary and Process Delays

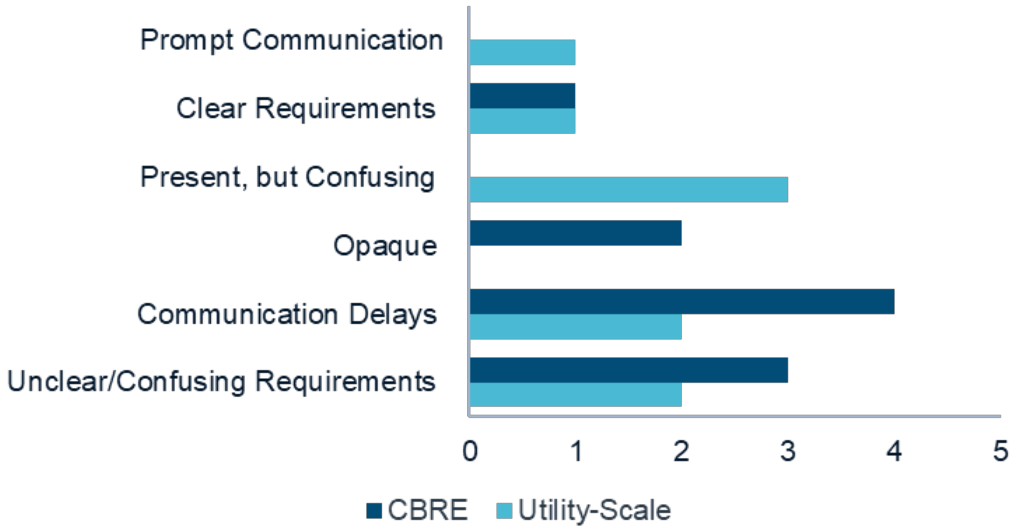
Survey Questions

- What is your view on overall timeline/steps for HECO's IRS process? Is there sufficient time for developers to prepare and submit technical requirements laid out in HECO's IRS process? In other words, are timeframes reasonable under each of the interconnection process phases? Please elaborate.
- From your perspective, what are key issues impacting the IRS timeline and follow-up interconnection process? In other words, which step in the interconnection process can lead to delays regarding responsibilities of the applicant and why?
- From your project/s IRS experience, are there any milestones that often experience delays? If yes, can you elaborate on these milestones and discuss what may have caused delays.
- If the project is in IRS process or under construction, can you respond to the following questions?
  - What is the status of your interconnecting project? Describe where your interconnecting project is in terms of HECO's defined IRS process.
  - If IRS process is completed, what were the respective durations of the system impact study (SIS) and facilities study (FS) phases?
- If the project is under operation, can you respond to the following questions?
  - What were the respective durations of the system impact study (SIS) and facilities study (FS) phases?
  - What was the duration of completing IRS process, i.e., from submitting information requested to completing the study?
- Have your project/s faced any interconnection-related delays?
- If yes, what are the most common reasons for missed timeline milestones (delays in outlined steps) by the Companies? In other words, from the initial bid submission to receiving COD assignment, which stage(s) resulted in the most delays from the IRS and other interconnection related process?
- Has a lack of payment (from the applicant) or delay in invoicing (from the Companies) led to a delay in the interconnection process?
- Have any other factors (e.g., permitting, siting, environmental studies, etc.) delayed the timeline of your project?

Survey Feedback Summary

Stakeholders were asked questions that related to the IRS stage of the interconnection process as well as any insight into other delays (occurring during IRS or later within the process). Related to the timeline and facilitation of the IRS process, stakeholders shared that requirements were unclear and confusing. In addition to comments about the clarity of requirements, stakeholders shared a greater concern related to communication delays between the developer and Hawaiian Electric's interconnection teams. The stakeholders who reported frequent delays stated that they were the result of communication errors. The communication errors were related to necessary replacements and/or changes in equipment for the interconnecting facility. Further, equipment changes and changes in project design often trigger cost increases and additional studies, which compound supply chain issues and communication errors. This cascading issue can be traced back to the clarity of part or all of the interconnection tariffs and the RFP requirements. Site inspections and device reviews, in addition to communication delays, were cited as primary causes for delays in reaching GCOD. As shown in *Figure 4-2*, three responses from stakeholders indicated prompt communication or clear requirements.

Figure 4-2: Interconnection IRS Timeline – Feedback

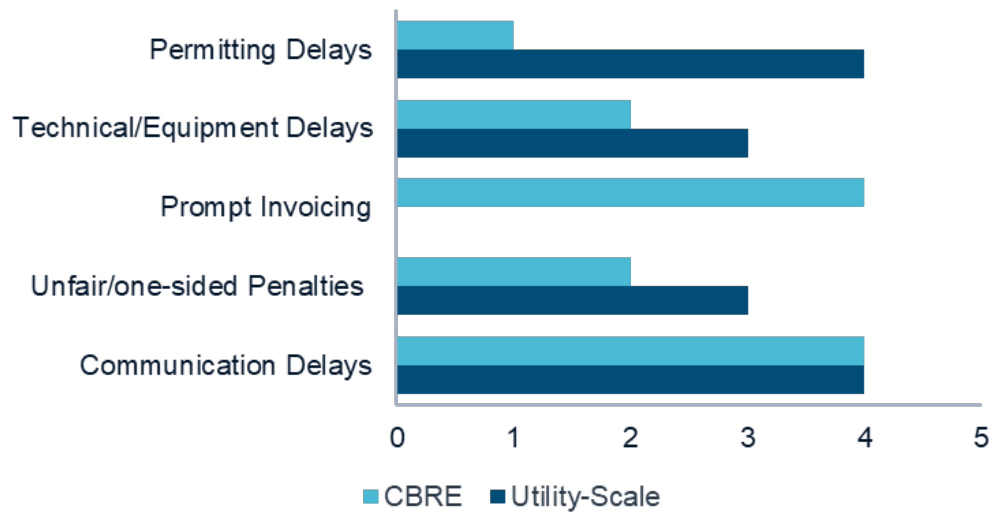


Regarding IRS delays, some stakeholders noted that the delays stem from multiple streams of communication for verification and coordination efforts. This was reported across multiple Hawaiian Electric teams responsible for interconnection. These issues underscore the importance of clarity of the process to mitigate delays. Developers expressed a preference for direct collaboration with the utility rather than funneling questions through third-party entities or consultants. Applicants navigating the Utility-Scale interconnection process voiced concerns about facing penalties if they are at fault for delays. As a result, stakeholders consider it unfair to incur financial penalties when there is no equivalent accountability or reciprocal consequences for delays attributable to the utility. The Study Team notes that the Commission recently established a PIM to impose penalties for utility-caused delays in future IRS processes, as discussed in Section 3.1.2.

Stakeholders reported that several factors impact the timeline to complete the interconnection process, including but not limited to, project size, complexity, technology, and available hosting capacity at the site. External factors, such as permitting, can also impact the interconnection timeline.

Study Team's Views: The Study Team agrees that the IRS timeline can be affected for various reasons including delays in gathering technical information, performing studies, and managing communication. We also observed that the Company has enhanced utility-scale interconnection timeline and process in Stage 3 through the learnings from the Stage 1 and 2 processes. For example, the Companies are aiming to reduce the total process time between the initial collection of the developer's model to the filing of the PPA including Project Specific Addendum with the Commission to a twelve-month period. They have instituted a new model checkout process, better highlighting requirements for developers to ensure that their models are sufficient upon initial submission, to mitigate issues and delays in the SIS phase. The 12-month utility-scale timeline for completing IRS process is achievable if the issues such as communication and time related with data collection that primarily causing delays are properly managed.

Figure 4-3: Interconnection Process Delays – Feedback



Study Team's Views: If not efficiently managed, communication between the project applicant and the project lead at the utility can lead to delays and a host of challenges. Effective notetaking, documentation of meetings, system design changes, or any other noted concerns shared between the developer and the utility are simple solutions to ensure project movement is aligned with mutual understandings. The Study Team finds monthly notices to the Commission to be a sufficient mechanism to aggregate the priority updates. However, a more detailed record log should be considered between the developer and point of contact at the Companies. Delays within the interconnection process are often characterized by complex technical exchanges and a need for clarity regarding regulatory requirements, timelines, and equipment needs or specifications. With difficulties in understanding, prolonged discourse of question-and-answer emails and/or phone calls add time to the schedule and bottleneck a project's operational approvals.

As a result, the developers may need to repeatedly adjust their project proposals, design, schematics, equipment, and configurations to align with the utility's standards and expectations. The Study Team recognizes a sophisticated platform should be investigated, which may enable notes, tabular accounting of all documentation shared between parties for the interconnecting project, as well as other applicable materials. As demonstrated in other jurisdictions with high application volumes, these platforms do take a longer lead time to implement and offer the highest benefit for high-volume application windows. In determining streamlining efficiencies for the interconnection timeline, the majority of sentiments from stakeholders and similar jurisdictions find communication efficiencies to be the most attainable delay reduction measure as the cumulative effect of these communication-related challenges underscores the need the need to mitigate the risks of delays, confusion, and costly design changes.

Another notable area for delays occurs with technical and equipment related modifications, construction, or general needs. Not only can this cause uncertainty for the project developer about applicability, but it also increases the costs for any triggered upgrades. This cost increase can also cause an additional delay window on either side. Other equipment related delays could be in the form of supply chain issues or variable jurisdictional requirements for equipment type, as well as changing device requirements.

Stakeholders reported that the engineering process and subsequent needs for review or restudy caused the greatest period of delays (categorized in *Figure 4-3* as "technical/equipment delays"). Stakeholders described the equipment delays as being caused by myriad of issues such as technology reviews resulting in equipment changes, technical specifications and industry standards requiring equipment upgrades, site visits with newly uncovered needs for additional modifications, and construction triggered by project or grid upgrades. External delays such as supply chain risk for equipment procurement and approvals for location siting from other jurisdictions were noted, as well. Developers opined on the need for exploration on whether the Companies can assist in streamlining that process or whether mitigation of external factors causing slowdowns is infeasible.

Stakeholders shared that the timelines estimated by Hawaiian Electric appear reasonable yet ambitious and for this reason, the timelines have often been unachievable, or milestones have been missed. The project data requested, and the timing of such data requests, were also reported as "problematic." As an example, stakeholders experienced challenges with the inverter modelling and meeting all of the Companies' requirements. Stakeholders reported that certain requirements were poorly defined and changed throughout the process (such as reactive power requirements or inconsistency between modelling requirements and PPA document, or inconsistencies between outcomes of the SIS and how those requirements are captured in the PPA IRS amendment).

4.3 IRS Status and Experience with Projects

Survey Questions

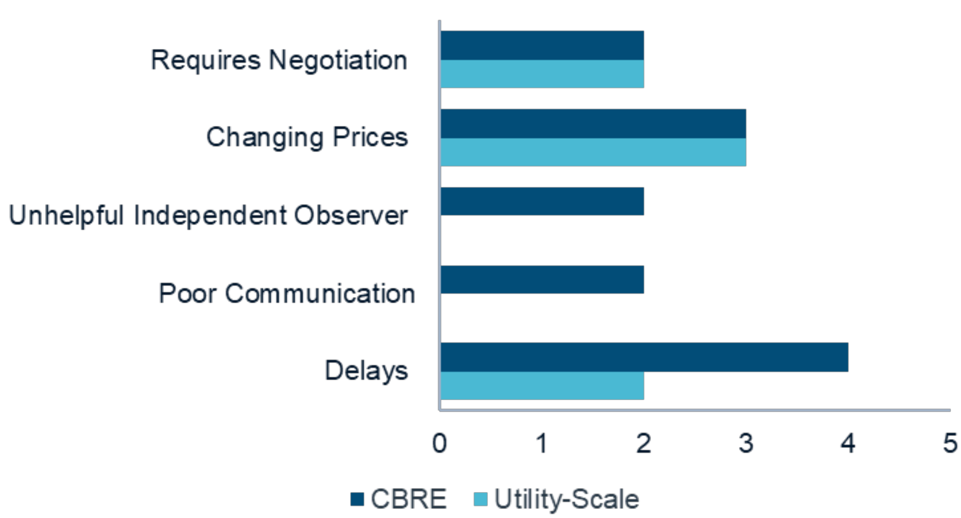
- If the project is in IRS process or under construction, can you respond to the following questions?
  - What is the status of your interconnecting project? Describe where your interconnecting project is in terms of HECO's defined IRS process.
  - If IRS process is completed, what were the respective durations of the system impact study (SIS) and facilities study (FS) phases?
- If the project is under operation, can you respond to the following questions?
  - What were the respective durations of the system impact study (SIS) and facilities study (FS) phases?

Survey Feedback Summary

For this series of questions, the Study Team asked stakeholders about their experiences in the interconnection process as compared with previous RFPs run by Hawaiian Electric and interconnection processes in other jurisdictions. Stakeholders provided insights relating to similar challenges, process evolutions, and successful project interconnections. Relating to the evolution of the process, stakeholders reported that the RFPs have generally improved with each successive round; however, despite this positive takeaway, the frequent changes also present a challenge in keeping up with changing requirements.

Related to interconnection costs, stakeholders highlighted receiving little support regarding invoices and itemization, and little explanation of additional fees outside of standard charges and estimates for grid upgrades. For community-based projects, this was a strong concern. CBRE stakeholders recommended exploring options to rate-base certain upgrades and providing additional clarity on forecasted costs. The Study Team found that prior experience with interconnection was a benefit for both CBRE and Utility-Scale developers, especially as it prepares developers to readily adapt to changes in interconnection policies and requirements.

Figure 4-4: IRS Status and Experience – Feedback



Study Team's Views: When determining the experience and understanding where the project is within the IRS process, the Study Team finds that developers often experience limited communication and changing price expectations from what available estimates were provided. From these interviews and previous engagements in other jurisdictions, the study team acknowledges that a developer's level of understanding of interconnection requirements can be correlated to its prior experience and number of successful past projects. In other words, those with limited experience or who may be nascent to the process of such an undertaking will likely require more guidance throughout the process. Accounting for the differences in prior experience of developers can help the utility plan its resources during the IRS process.

4.4 IRS Related Fees, Cost Estimates, and Actuals

Survey Questions

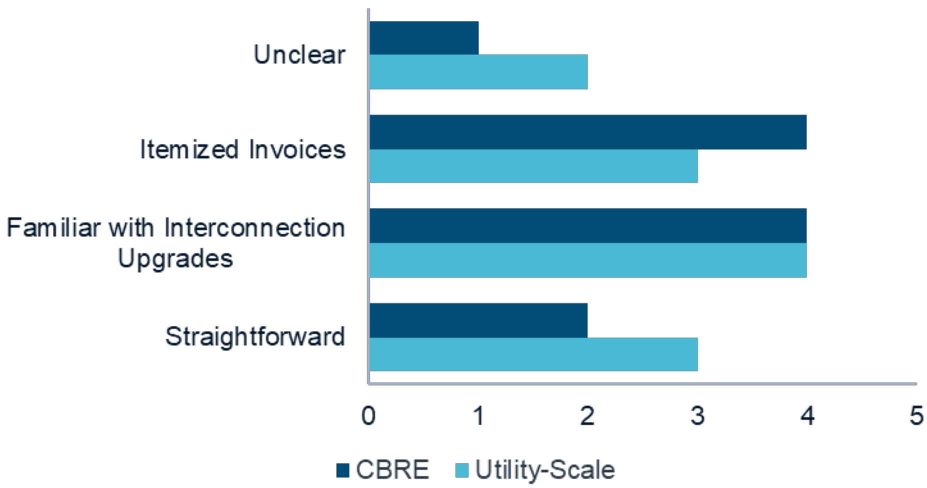
- What is your understanding of HECO's process for charging IRS related fees?
- Did the Companies provide a cost estimate for the interconnection costs, SIS, and FS that would be billable (with true-ups) to the customer? Do you feel the cost estimates were clearly and satisfactorily broken down?
- What types of upgrades were triggered by the interconnecting project, if any, and what were the total attributable costs?
- How are the Companies accounting for your responsible expenditures related to system upgrades? Describe your experience.
- Based on your experience, were there any system upgrades that you were unfamiliar with?
- From the perspective of the interviewee, were certain mitigations or upgrades assigned to the applicant that may have been otherwise funded through other sources, lower-cost opportunities, or system planning functions? (i.e., standard grid enhancements planned by the Companies)
- If so, did you contest any costs? And what was the outcome, if the case?
- During the IRS process of the project, has your team experienced unexpected or unexplained costs associated with project management fees? If so, explain the situation and unexpected costs.
- Please describe the true-up process for additionally incurred fees.
- Are invoices itemized with the upgrades and mitigations?
- Have any of the cost estimates changed within a significant deviation (say more than twenty-five precent deviation) from the interconnection cost estimates forecasted by the Companies? If so, how much and in which direction?
- Prior to the SIS and FS phases, what was the first payment paid to HECO (for each project)?
- What and how much were the second payments that were incurred to complete the IRS Amendment?
- Were the SIS and FS costs presented clearly and in detail in any formal estimate?
- Was a summary of findings and additional costs communicated to the interviewee (for each project)?

Survey Feedback Summary

Stakeholders reported the most uncertainty with interconnection costs among all actual project expenses. While some predictable costs have been woven into the IRS and study phases, each interconnecting project presents a unique challenge to standardized utility accounting practices. According to stakeholders, grid reliability needs, technological advancements, siting, existing infrastructure, and hosting capacity concerns all contribute to the complexity of interconnection cost estimation. Consequently, assigning cost responsibility between the Companies and the applicants can be a complicated and controversial effort that requires transparency and predictability. Project management fees, for example, have historically lacked clarity and transparency.

In general, stakeholders reported that IRS fees were generally acceptable, clear, and relatively certain. As shown in *Figure 4-5*, stakeholders provided mixed feedback on other types of costs. The majority of stakeholders were familiar with the system upgrades that their projects necessitated and found the fees straightforward; however, stakeholders did not always agree with the costs of these upgrades that were assigned to their project. Stakeholders believe that costs of upgrades that have perceived benefits for all customer classes should be rate-based (or shared across all customers). Alternatively, stakeholders believe that these upgrades should result from routine system capacity planning, and therefore paid for out of the utility's rate base.

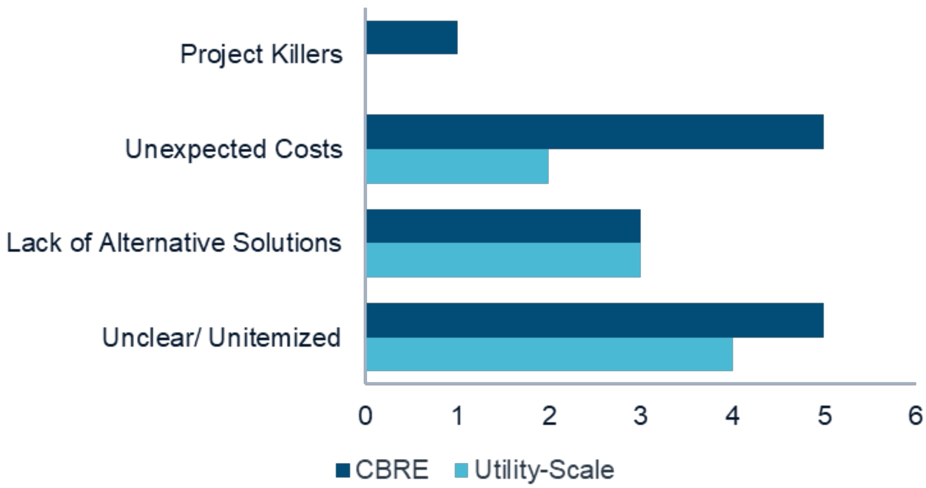
Figure 4-5: IRS Related Fees – Feedback



Study Team's Views: It is reasonable for developers to seek predictability in costs associated with their projects. In the Stage 3 RFP process, the developers are required to incorporate estimated interconnection cost in their overall bid price. The developers prepared the interconnection cost estimates based on the 'unit-cost' guide provided by the Companies and their own experience. The actual interconnection costs are determined after the completion of the IRS study. Uncertainty around the interconnection costs estimates are understandable as the actual interconnection upgrade costs are determined after the completion of the IRS study. However, the Companies should communicate detailed study results as early as possible with the developers, especially if the interconnection costs are materially different than the estimates.

Stakeholders reported that uncertainties in the total cost of the project can evolve into concerns about their project's viability and create a need for renegotiating their PPA pricing. In some cases, the disparities between forecasted costs and actual costs were referred to by one stakeholder as "project killers", where project viability becomes uncertain. The project viability can quickly deteriorate without a level of cost predictability, according to stakeholders. Stakeholders also shared concerns regarding fees and cost methodology, as shown in Figure 4-6.

Figure 4-6: Interconnection Cost Estimates – Feedback

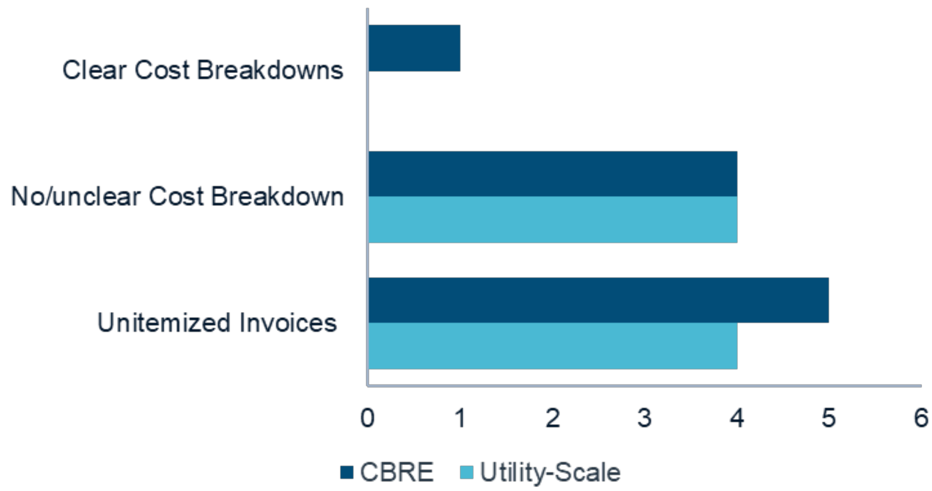


Study Team's Views: The complexity of forecasted versus actual interconnection costs, and the subsequent adjustments or true-ups, presents a consistent challenge in the interconnection process. Initially, forecasted costs are provided to developers based on fixed fees such as study and application costs, and pricing estimates of known grid upgrades, studies, and infrastructure modifications necessary for a project. Numerous reasons can cause the deviation from forecasted costs over the course of the project including scope changes, fluctuations in material and labor costs, external factors such as supply chain issues and material availability, long lead times for the construction to take place, and any unforeseen technical requirements that necessitate equipment or design changes. Accurate invoicing is essential for achieving fair allocation of all of these costs. Many developers do not understand or agree with the utility's methodology for cost allocation and argue that there are shared benefits of integrating projects due to the societal, environmental, and carbon reducing attributes that are shared by all ratepayers. Regulators across jurisdictions are still working to create and enforce clear policies that guide fair and reasonable cost allocation.

Nevertheless, cost deviations can occur regardless of the clarity of policies and improvements to forecasted costs. These deviations can lead to financial uncertainty for developers, as true-up processes adjust the final costs to reflect the actual expenses incurred. Furthermore, the timing of true-ups can affect project financing schedules and cash flow, especially in large-scale projects. The Study Team finds that the financial risks involved can cause a project to withdraw entirely from the process.

As shown in *Figure 4-7*, stakeholders emphasized a need for clear and itemized invoices in the interconnection process. Stakeholders recommended improvements to address cost transparency such as discovery meetings wherein the Companies would provide an explanation and a comprehensive overview of all anticipated costs. Stakeholders shared that project management fees do not include a cost breakdown, nor an explanation of how the project management fees are apportioned across projects (i.e., relative to interconnection costs, interconnection-related work, etc.). The project management fees do not include a description of general operational tasks nor activities performed across groups of projects, to understand how these costs are shared. Lastly, it is unclear whether the time billed to project management is accounted for in a way where estimated fees can be provided. Notably, stakeholders raised concerns about cost accountability after comparing the Companies' estimates to that of the EPC contractors tasked to perform the same scope of work and finding that the cost differences were vastly different.

Figure 4-7: Actual Costs and True-Ups – Feedback



Study Team's Views: Improving the accuracy of initial cost estimations is paramount. This could involve utilities conducting more detailed preliminary assessments and incorporating buffer amounts and percentage bands to account for potential cost overruns. For example, in California, regulators implemented a "Cost Envelope Option" to address similar concerns with cost predictability for more streamlined projects. By adopting these measures, the process of aligning forecasted and actual interconnection costs can become more transparent and manageable, reducing the financial uncertainties and burdens for developers and contributing to a more cooperative and efficient interconnection environment. The regulators recommend incorporating a "cost envelope" (e.g., 25 percent in either direction of forecasted costs) to account for a reasonable level of uncertainty in the cost estimates, or to use as an enforceable sharing savings or penalty mechanism. Secondly, implementing a cap on the percentage increase in true-up costs could protect against large swings in financial variances while incentivizing the Companies, through penalties for example, to cover the difference in overrun.

The Study Team recommends investigating the potential to rate-base costs that benefit Hawaiian Electric's grid as a whole. The Study Steam also recommends enhancing the communication and documentation process to ensure that developers are regularly updated about potential cost changes as their project progresses. This approach would allow for better financial planning and risk management. Additionally, fostering collaborative partnerships between the Companies, other entities, and developers can lead to more innovative solutions, such as cost-sharing. agreements for upgrades that benefit the broader grid system, thereby distributing the financial impact more equitably among those who benefit. Finally, the Companies could explore the possibility of insurance products or financial instruments designed to hedge against significant cost escalations.

4.5 Technical Analysis Requirements

Survey Questions

- Were requests for information made by the Companies appropriate in order to facilitate the SIS and FS phase?
- Were technical results summaries understandable and clearly communicated to the interviewee?
- Are there any common challenges faced during the SIS an FS process and do the Companies take action to reconcile them?
- Do you have an opinion of whether the revealed upgrades due to the interconnecting project were fair and justified?
- Did any issue on your project trigger a re-study or additional studies? If so, could you please describe those circumstances. Did these studies lead to a delay in the interconnection process, and if so, how long was this delay?

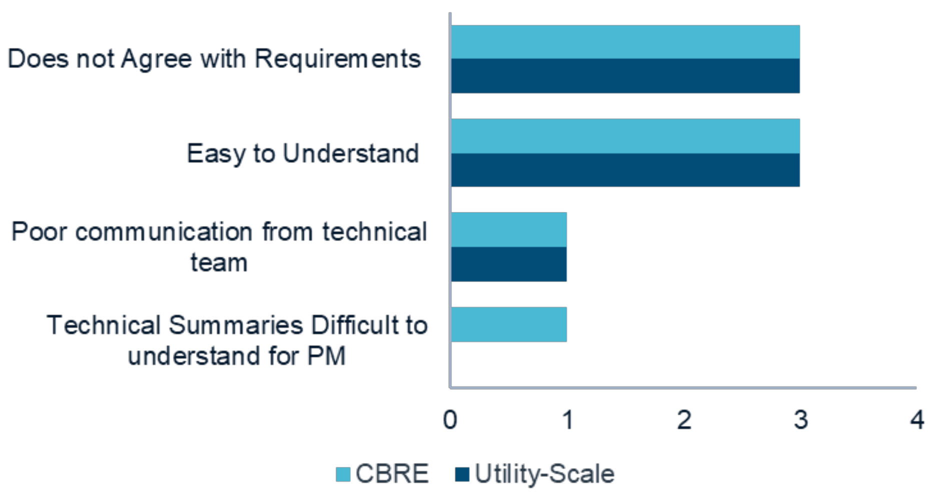
Survey Feedback Summary

Stakeholders reported challenges related to technical characteristics and system modeling, and highlighted concerns that differing interpretations of the models between developers and the Companies can impact system design differently. This invariably impacts the interconnection agreements and can lead to modifications of the specifications. These modifications can cause concerns over potential re-studies and delays to the IRS timeline.

Stakeholders with experience interconnecting in other jurisdictions reported that approved equipment lists have been helpful to avoid differences in interpretations and outcomes of the modeling and system design processes. Approved equipment lists could be developed by the Companies through testing and assuring that the specifications of the device are permitted and do not adversely impact the grid. Approved equipment lists can also reduce delays caused by equipment changes and the associated re-studies.

As shown in *Figure 4-8*, stakeholders shared that external bottlenecks with supply chains may occur, which are a widespread concern also shared by the Companies. In general, stakeholders did not disagree with the need for specifications but would encourage the Companies to investigate standardizing known and accepted equipment standards to enable streamlined design activities. Regarding re-studies, stakeholders expressed that design modifications could be rectified if the upfront modeling exercises were more useful and less time-consuming and if detailed characteristics of the Companies' system were provided ahead of the RFP. Modeling delays could be mitigated by performing fewer decentralized and siloed modeling activities.

Figure 4-8: Technical Analysis Requirements – Feedback



Study Team's Views: Currently the company does not provide upfront grid modeling information, rather they provide limited technical information at the POI on as-requested basis. Developers and their modeling consultants consequently have little understanding of how their project will impact the grid. However, the Company requires extensive modeling upfront from all developers. The modeling is cost intensive and does little to inform the developers on accurate location and potential upgrades needed to the grid. It generally overburdens the developers in terms of cost and time, while also having to remodel later on in the process once final size and location is selected. Developers benefit most from having access to comprehensive grid models at the appropriate time in the bid process (not in the initial bid phase).

Stakeholders recalled situations in which changes were anticipated to the Companies' procurement requirements, yet these changes occurred late in the design process. Stakeholders reported using a "letter of equivalence" to circumvent this issue, but this approach has not always been accepted by the Companies. Stakeholders reported external constraints related to permitting approvals from other agencies, but also reported the willingness to work with the Companies to streamline this process. The Companies currently possess the necessary relationships and structure to streamline the permitting process that the developers lack. As such, many of the developers echoed the sentiment of a desire to partner with the Company to best streamline the permitting process.

Stakeholders also relayed technical concerns that caused delays during the interconnection process; however, stakeholders reported that most of these delays were "acceptable" as a part of the known and anticipated process. Stakeholders in the CBRE process repeated earlier concerns that summaries of technical overviews were unclear and felt that re-studies could have been prevented if prior insight had been clearly marked and provided to the applicant ahead of the certain milestones.

4.6 Customer Service, Communication, and Recordkeeping

Survey Questions

- Was the interviewee assigned a point of contact (POC) from HECO in handling the interconnecting project?
- Please describe the modes and methods in which you would provide and receive information throughout the interconnection process.
- Were there any concerns that required escalation to superiors at the Companies? If so, please describe the circumstance and resolution process.
- On average, how long were the response times from the POC and/or customer service team?
- Please describe your overall experience working with the different divisions at the Companies respective to the various milestones and phases.
- Was the interviewee assigned a point of contact (POC) from HECO in handling the interconnecting project?
- Please describe the modes and methods in which you would provide and receive information throughout the interconnection process.
- Were there any concerns that required escalation to superiors at the Companies? If so, please describe the circumstance and resolution process.
- On average, how long were the response times from the POC and/or customer service team?
- Please describe your overall experience working with the different divisions at the Companies respective to the various milestones and phases.
- Please describe your project's user interface experience with the online interconnection platforms.
- To your understanding, how was information stored on the side of HECO?
- What was your process of requesting and receiving information related to the project(s)?
- How were milestones tracked and communicated throughout each phase of the interconnection process?
- How was confidentiality handled by the Companies, if applicable?
- Did you experience challenges in transferring information to another department, division, or personnel? If so, please describe the situation.
- Did recordkeeping and process reporting practices contribute to any delays in the interconnection process? If so, please elaborate. Does the interviewee have an opinion on the recordkeeping practices of the Companies?

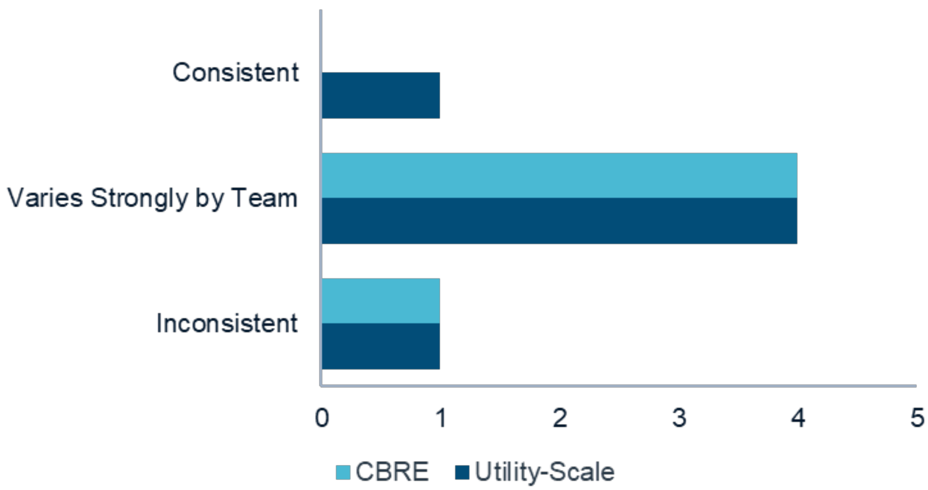
Survey Feedback Summary

The Study Team found mixed statements on coordination with customer service and the divisions at the Companies at different stages in the interconnection process. In general, the methods for communicating were standard and similar (e.g., email and phone). However, recordkeeping of these conversations, notes, and information handoffs were not clearly laid out to the developers. Therefore, handling project information and handoff of notes were unknown processes to those interviewed. Stakeholders reported lacking confidence in the Companies' recordkeeping practices, and specifically, tracking of specific interactions, conversations, and activities. However, all other public and standardized documentation was retrieved or referenced when needed throughout the interconnection process. In other words, the developers reported that the Companies' track relevant information and documentation when necessary to advance the project or meet certain milestones but lack documentation of the day-to-day coordination on their projects.

Additionally, stakeholders reported inconsistencies in the understanding of the interconnection process among the departments at Hawaiian Electric. For example, stakeholders reported that the customer installation division can have trouble understanding where to transfer calls and distribute information based on the developer's inquiries.

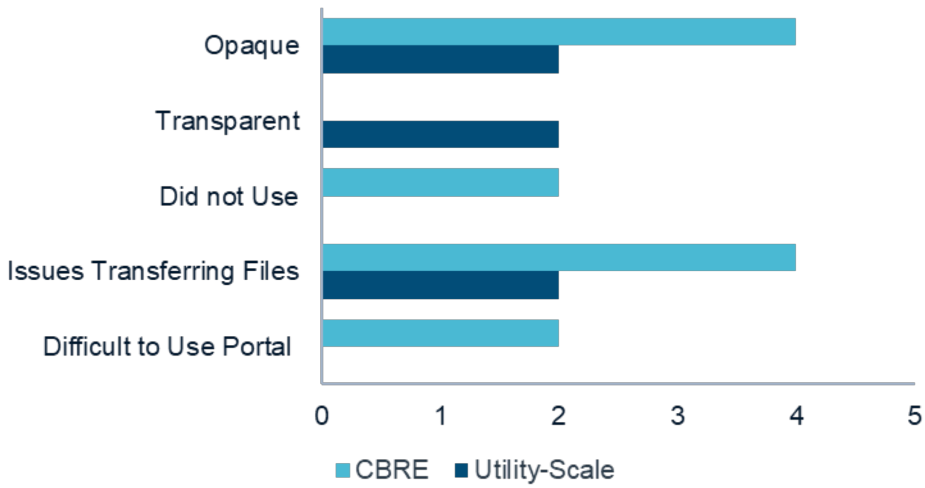
As a process improvement, stakeholders recommend recording conversation minutes or creating a detailed record of communication to improve coordination procedures. This would also relieve the timeline delays in communicating updates to third parties, as well. While interactions with the personnel are generally positive and developers acknowledge the evolving process, stakeholders encouraged the Companies to find efficiencies in information handoffs and milestone updates.

Figure 4-9: Customer Service and Communication – Feedback



Stakeholders generally reported positive experiences with working with project managers at the Companies and felt their projects had the attention and bandwidth allocated to their needs. With the engineering groups, stakeholders reported similar concerns with information handoffs, as reported above. Some ideas to streamline these practices included incorporating a verification mechanism or a procedure to track updates and engineering notes. As shown in *Figure 4-10*, stakeholders reported issues revealing a lack of understanding or user experience within any online website directories related to the interconnection process. Stakeholders understand the need to maintain confidential information, which may require non-disclosure agreements or other means to ensure sensitive information is monitored. This may assist the RFP processes in the future. Stakeholders that did not report using information and stored progress reports in the Companies' management system were reported as "did not use" in *Figure 4-10*; however, they still otherwise agreed with the recommendation for a repository and portal update.

Figure 4-10: Recordkeeping Practices – Feedback



Study Team's Views: Effective management of interconnecting projects starts with the workload planning to align projects with respective project managers and related departments. The Study Team echoes similar themes addressed by the developers. The Companies currently rely on time-stamped notices, such as email communications, to maintain records of the different milestones for the interconnection process; they do not maintain a database to store this information. The Companies do not make use of an all-inclusive repository for information sharing between the developers and the utility personnel.

Information retrieval and record keeping systems within the interconnection process should move away from an email-based communication to an integrated information management system. Such system could allow the Companies to streamline repetitive tasks and workflows, standardize process, automate integrating with other systems, and communicate effectively with the developers.

4.7 General Comments, Dispute Resolution, and Independent Engineer (Stage 3 RFP Process)

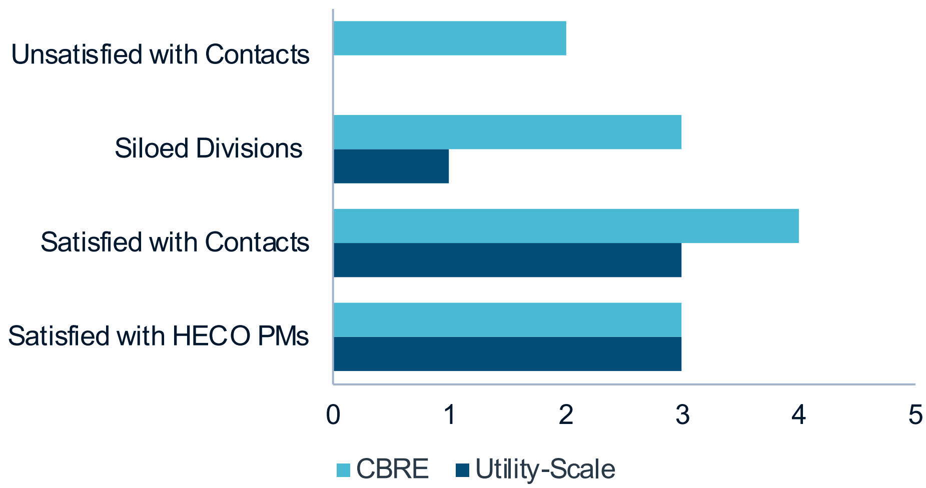
Survey Questions

- Please describe successes and positive experiences with interconnecting a project. What worked well and what can be applied to a program enhancement?
- Are there areas in which the Companies can streamline interconnecting projects? Please describe.
- Do you have any other interconnection related experience that you would like to share with us?
- What issues might trigger a formal dispute resolution process through the Commission's facilitation?
- Have there been any instances where a circumstance may have warranted this higher elevation of mediation? If so, please describe the situation.
- What are acceptable timelines in resolving varying levels of grievances through a formal dispute resolution process?
- Do you have any additional comments regarding program enhancements to mitigate future concerns?
- Are you aware of any interconnection-related dispute resolution process established by the Commission? If yes, please share your understanding and whether your projects have considered using the established dispute resolution process.
- If you are currently involved in the Stage 3 RFP, please describe your understanding of the role of the Independent Engineer. Have the Companies provided any information to you regarding the role of the Independent Engineer?

Survey Feedback Summary

Lastly, stakeholders provided general comments on the interconnection process and recent improvements such as with newly established mediation functions in the current Stage 3 RFP. General comments included feedback which may have fallen outside of the conventional study categories or were reinforcing earlier points. For example, the majority of stakeholders expressed positive experiences with Hawaiian Electric's project management teams, yet they reiterated that the siloes that exist across divisions can create bottlenecks in information hand-offs, as described in *Figure 4-11*.

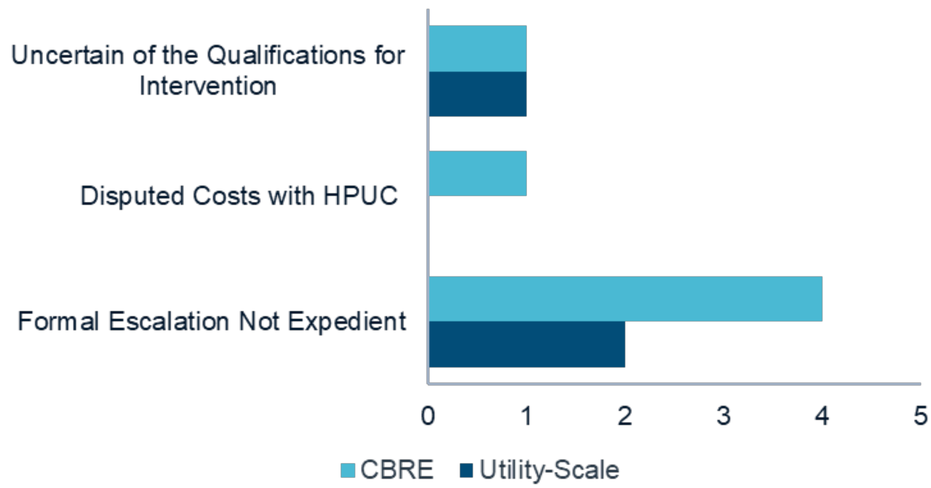
Figure 4-11: Uncategorized General Comments – Feedback



Due to the infancy of the IDRP, the Study Team did not anticipate in-depth feedback regarding experience with navigating the dispute process. However, the Study Team asked hypothetical questions related to the usefulness of this framework and what additional considerations may be made to further enhance the implementation of the IDRP. The Study Team did not address the distinction between Formal Dispute Resolution and IDRP. Formal Dispute Resolution is another venue for disputes not specifically related to interconnection, that was not addressed in this study.

In general, the majority of insights reflected the need for expediency when elevating concerns to the level of Commission intervention. Stakeholders appreciate the intention of the IDRP as it recognizes the need to rectify issues, however, with anticipation of further delays to resolve elevated grievances, developers were hesitant to explore routine use of the interventions. For concerns that may require fundamental changes and precedents for future projects, stakeholders did appreciate the design of the IDRP. In several hypothetical situations presented to the stakeholders, the Study Team found that developers may have benefited from the IDRP.

Figure 4-12: Dispute Resolution Process Awareness – Feedback



Study Team's Views: An interconnection dispute resolution process is a critical mechanism to mitigate delays and make room for efficiencies if 1) the dispute is an interconnection-related technical issue and meets the criteria of an IDRP type of issue and 2) the developer opts to use the IDRP to resolve the dispute instead of using the current existing Formal Dispute Resolution process available in all projects (Utility-Scale and CBRE). Over time, the dispute resolution process can reduce time spent addressing common concerns, establish precedent, and clarify ambiguities within the interconnection process. Moreover, the process can foster a sense of fairness and transparency and build trust in a reasonable timeline for the interconnection process. While remaining impartial, the mediation team can address issues in a systematic manner, which expedites current disputes and frames and addressable avenue to handle future disagreements.

Most importantly, insights gained from any dispute resolution process (Formal or IDRP) can be invaluable for enhancing policies and procedures. By analyzing causes and achieving resolution, improvement areas can be identified, which will also be critical as evolving technologies and market conditions continue to improve the timeliness and cost of interconnection. Ultimately, the process will facilitate a smoother and more predictable interconnection experiences for all involved parties**.**

Lastly, unless the entities were directly involved in the Stage 3 RFP process, the Study Team found no general awareness into the operational activities of the IE, the current activities the IE carries out, or any other significant identifier of the process. As such, the Study Team found no drivers to record regarding general sentiments to roll up into graphical representation. The Study Team, however, did compile recommendations associated with future bid enhancements in Section 6 of this report.

5 Status of Interconnection: 2015-2022

5.1 Summary of Renewable Projects: 2015-2022

The following section provides a summary of 38 eligible projects that have either interconnected to Hawaii's electric utility grid over the last seven years (2015-2022) or are currently under development. Although other renewable generation projects have been developed during the same period, these 38 projects meet the criteria set in Act 201 – renewable projects greater than 5 MW, and/or CBRE projects of any size. All 38 projects accounted for in our reporting have an executed PPA with the respective Company whose grid it will interconnect to. There are three projects under PUC's consideration for PPA approval; however, Hawaiian Electric request suspension of one of these projects. During the same period, 14 projects were cancelled.

Table 5-1, *Table 5-2*, and *Table 5-3* provide a summary of projects by project developer type and current status.

Table 5-1: Status of All Renewable Projects from 2015-2022[63] (as of 11/15/2023)

Project Status	Number of Projects
Interconnected	15
Under Development	23
PPA Submitted to PUC	3
Cancelled	14

Table 5-2: Total Number of Active Renewable Projects from 2015-2022 (as of 11/15/2023)

Project Developer Type	Interconnected	Under Development	Total Projects
IPP	11	9	20
Self-Build	1	0	1
CBRE	3	14	17
Total Projects	15	23	38

Table 5-3: All Renewable Projects by Developer Type, Island, and Interconnection Status from 2015-2022 (as of 11/15/2023)

	O'ahu	Maui	Hawai'i	Total
Interconnected				
BESS	-	-	-	-
PV	10	1	-	11
PV+BESS	2	-	1	3
Wind	1	-	-	1
Sub-Total	13	1	1	15
Under Development				
BESS	1	-	-	1
PV	2	1	3	6
PV+BESS	6	6	4	16
Wind	-	-	-	-
Sub-Total	9	7	7	23
Total Projects	22	8	8	38

Table 5-4 provides an aggregate size and number of projects by technology type and capacity that have been procured via the various processes during the 2015-2022 period. The renewable projects that have already been interconnected in the Companies' system are mainly solar photovoltaic (PV) facilities. However, most of the projects that are currently under development (that were procured via Stage 1 and 2 RFP) are paired solar PV and BESS facilities.

[63] Includes 3 additional projects which have active PPAs submitted to the PUC.

Table 5-4: All Renewable Projects by Technology Type, Size, Capacity, and Count from 2015-2022 (as of 11/15/2023)

	O'ahu	Maui	Hawai'i	Total
Interconnected				
BESS	-	-	-	-
PV	175 MW (10)	0.02832 MW (1)	-	175 MW (11)
PV+BESS	75 MW/300 MWh (2)	-	30 MW/120 MWh (1)	105 MW/420 MWh (3)
Wind	24 MW (1)	-	-	24 MW (1)
Under Development				
BESS	185 MW/565 MWh (1)	-	-	185 MW/565 MWh (1)
PV	7.72 MW (2)	0.25 MW (1)	5.75 MW (3)	13.72 MW (6)
PV+BESS	151.5 MW/739.5 MWh (6)	85.2 MW/342.1 MWh (6)	39 MW/156 MWh (4)	275.7 MW/1237.6 MWh (16)
Wind	-	-	-	-

Figure 5-1, *Figure 5-2*, and *Figure 5-3* present the geographic spread of renewable projects that meet the criteria laid out in Act 201 within each island utility territory.[64]

[64] Phase 2 CBRE projects are not included

Figure 5-1: Hawaiian Electric Renewable Projects in Oahu County Interconnected and Under Development from 2015-2022 (as of 11/15/2023)

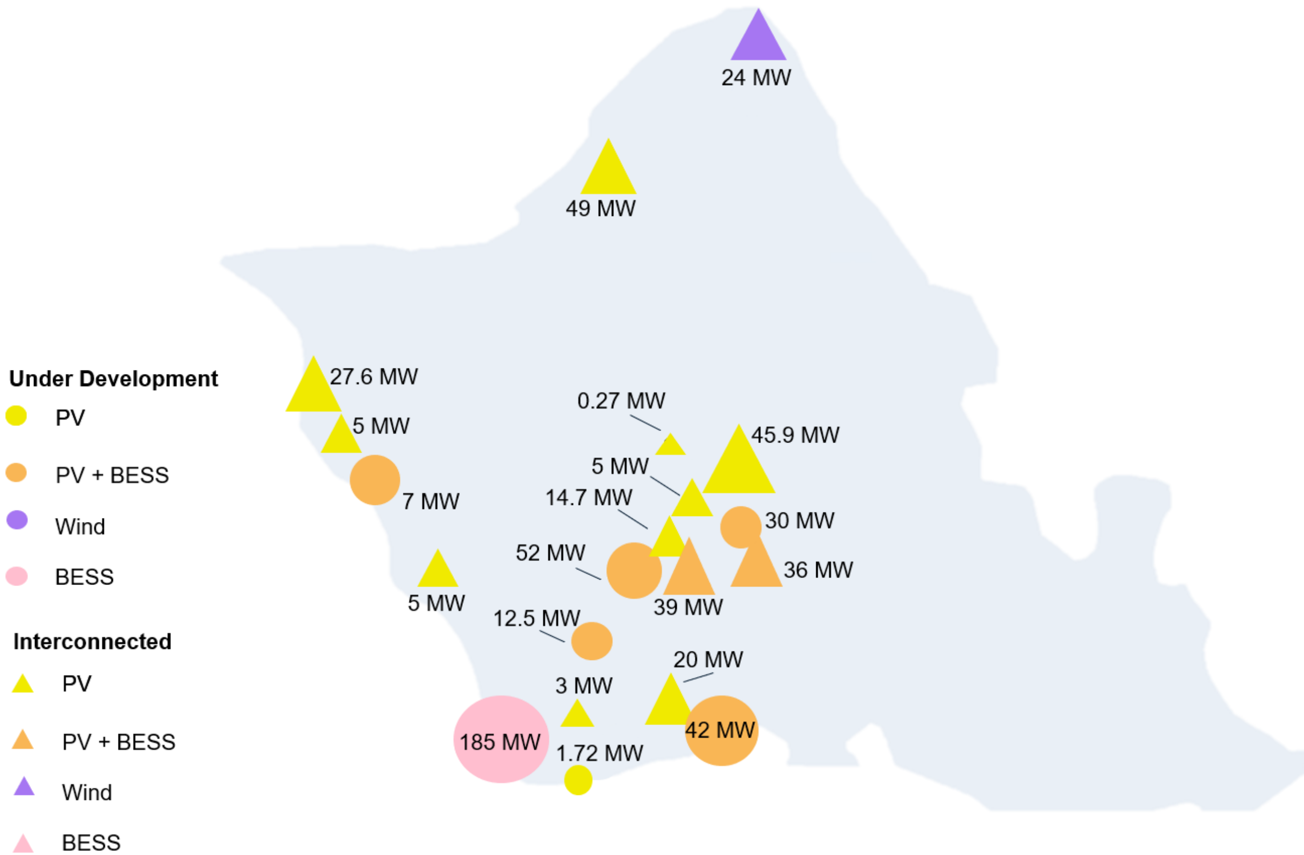


Figure 5-2: Maui Electric Renewable Projects in Maui County Interconnected and Under Development from 2015-2022 (as of 11/15/2023)

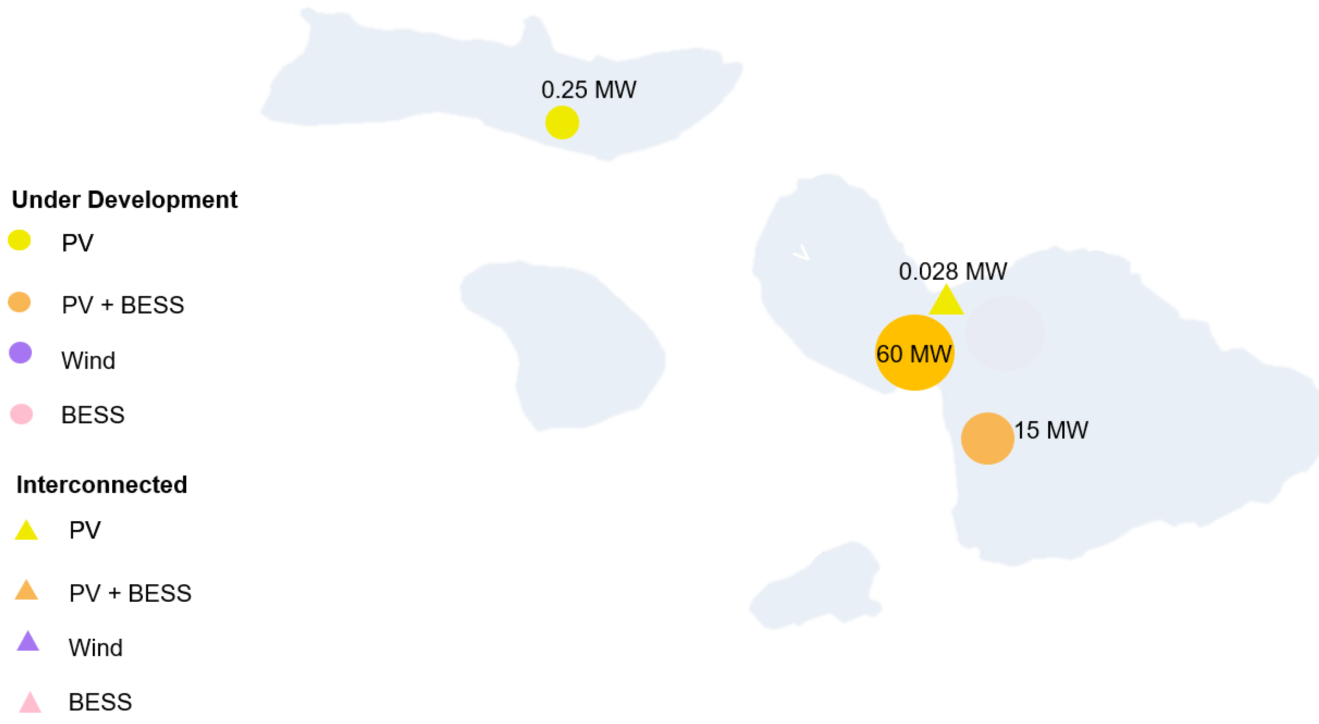
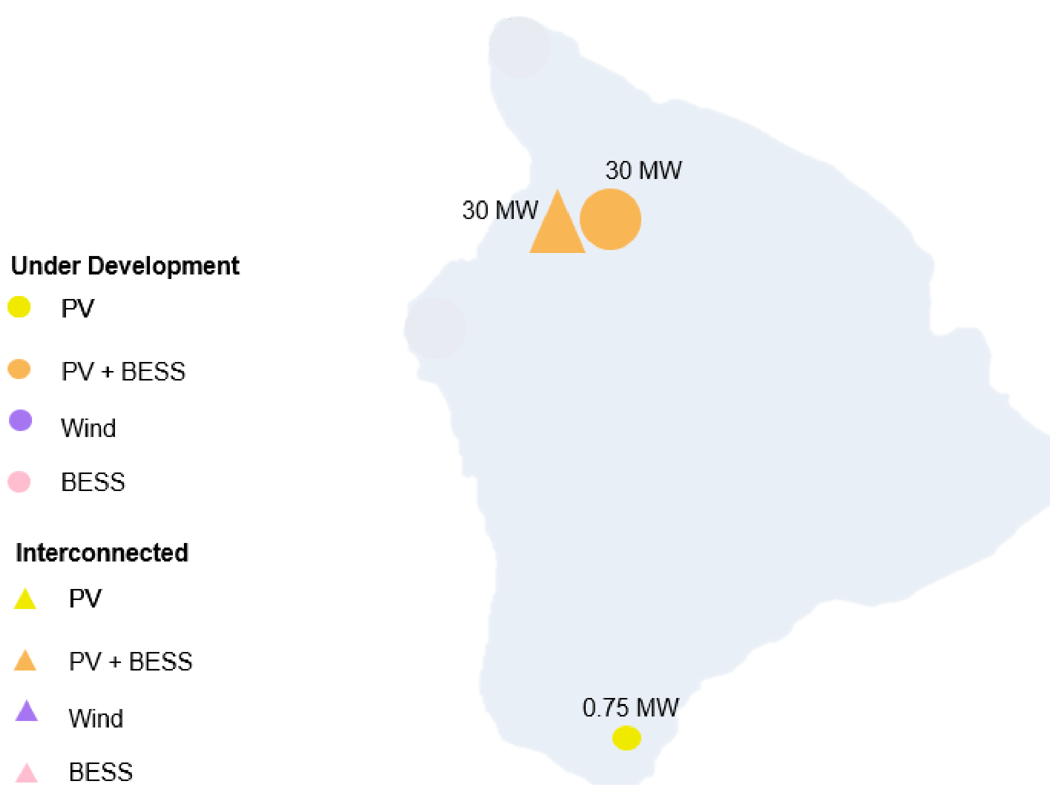


Figure 5-3: Hawaiian Electric Light Renewable Projects in Hawaii County Interconnected and Under Development from 2015-2022 (as of 11/15/2023)



5.1.1 Summary of Utility-Scale IPP and Self-Build Renewable Projects that are Interconnected or Under Development from 2015-2022

Table 5-5 and *Table 5-6* provide an aggregate size and number of Utility-Scale projects by technology type and capacity that have been interconnected or are under development for IPPs and Self-Builds from 2015-2022. The renewable projects that have already been interconnected in the Companies' system are mainly solar photovoltaic (PV) facilities. However, most of the projects that are currently under development (that were procured via Stage 1 and 2 RFP) are paired solar PV and Battery Energy Storage System (BESS) facilities.

Table 5-5: IPP/Self-Build Utility-Scale Renewable Projects by Technology Type, Island, and Interconnection Status from 2015-2022 (as of 11/15/2023)

County	O'ahu	Maui	Hawai'i	Total
Interconnected				
BESS	-	-	-	-
PV	8	-	-	8
PV+BESS	2	-	1	3
Wind	1	-	-	1
Sub-Total	11	-	1	12
Under Development				
BESS	1	-	-	1
PV	-	-	-	-
PV+BESS	5	2	1	8
Wind	-	-	-	-
Sub-Total	6	2	1	9
Total Projects	17	2	2	21

Table 5-6: IPP/Self-Build Utility-Scale Renewable Projects by Technology Type, Size, Capacity, and Count from 2015-2022 (as of 11/15/2023)

	O'ahu	Maui	Hawai'i	Total
Interconnected				
BESS	-	-	-	-
PV	172.2 MW (8)	-	-	172.2 MW (8)
PV+BESS	75 MW/300 MWh (2)	-	30 MW/120 MWh (1)	105 MW/420 MWh (3)
Wind	24 MW (1)	-	-	24 MW (1)
Under Development				
BESS	185 MW/565 MWh (1)	-	-	185 MW/565 MWh (1)
PV	-	-	-	-
PV+BESS	143.5 MW/701 MWh (5)	75 MW/300 MWh (2)	30 MW/120 MWh (1)	248.5 MW/1121 MWh (8)
Wind	-	-	-	-

5.1.2 Summary of CBRE Projects that are Interconnected and Under Development from 2015-2022

Error! Reference source not found.*Table 5-7* and *Table 5-8* provide an aggregate size and number of projects by technology type and capacity that have been interconnected or are under development for CBRE projects from 2015-2022. The renewable projects that have already been interconnected in the Companies' system are all solar photovoltaic (PV) facilities. However, most of the projects that are currently under development are paired solar PV and BESS facilities.

Table 5-7: CBRE Projects by Technology Type, Island, and Interconnection Status from 2015-2022 (as of 11/15/2023)

	O'ahu	Maui	Hawai'i	Total
Interconnected				
BESS	-	-	-	-
PV	2	1	-	3
PV+BESS	-	-	-	-
Sub-Total	2	1	-	3
Under Development				
BESS	-	-	-	-
PV	2	1	3	6
PV+BESS	1	4	3	8
Sub-Total	3	5	6	14
Total Projects	5	6	6	17

Table 5-8: CBRE Projects by Technology Type, Size, Capacity, and Count from 2015-2022 (as of 11/15/2023)

	O'ahu	Maui	Hawai'i	Total
Interconnected				
BESS	-	-	-	-
PV	3.27 MW (2)	0.02832 MW (1)	-	3.29832 MW (3)
PV+BESS	-	-	-	-
Under Development				
BESS	-	-	-	-
PV	7.72 MW (2)	0.25 MW (1)	5.75 MW (3)	13.72 MW (6)
PV+BESS	8 MW/38.5 MWh (1)	10.2 MW/42.1 MWh (4)	9 MW/36 MWh (3)	27.2 MW/116.6 MWh (8)

5.2 Historical Interconnection Metrics and Timeline

5.2.1 Interconnection Metrics of Renewable Projects from 2015 – 2022

Out of 38 total projects identified, 14 have been interconnected to the Companies' system, whereas the remaining 24 projects are currently under development. Out of 20 IPP-built projects, 11 have interconnected, whereas 9 projects remain under development. IPP projects that are currently being developed were procured via the Stage 1 and 2 RFP processes. Among the 17 CBRE projects, 3 have been successfully interconnected in the system, 14 are under development. The summary also includes 1 self-build project: West Loch Solar One (PV, 20 MW) that reached COD on November 11, 2019. *Table 5-9* and *Table 5-10* provide a summary of projects by project developer type and current status.

Table 5-9: Total Number of Active Renewable Projects from 2015-2022 (as of 11/15/2023)

Project Developer Type	Interconnected	Under Development	Total Projects
IPP	11	9	20
Self-Build	1	0	1
CBRE	3	14	17
Total Projects	15	23	38

Table 5-10: All Renewable Projects by Developer Type, Island, and Interconnection Status from 2015-2022 (as of 11/15/2023)

	O'ahu	Maui	Hawai'i	Total
Interconnected				
BESS	-	-	-	-
PV	10	1	-	11
PV+BESS	2	-	1	3
Wind	1	-	-	1
Sub-Total	13	1	1	15
Under Development				
BESS	1	-	-	1
PV	2	1	3	6
PV+BESS	6	6	4	16
Wind	-	-	-	-
Sub-Total	9	7	7	23
Total Projects	22	8	8	38

Figure 5-4 includes the actual costs for interconnection for all projects that have reached commercial operation over the last seven years (2015 – 2022) under the Stage 1 RFP, Feed-In-Tariff (FIT) 3, and Waiver[65] projects. These costs include all construction costs for COIF, gen-ties, and any fees for respective SIS and FS. The figures also include the capacity of the renewable projects. The Companies do not track costs associated with project management of the IRS process separately. The total interconnection cost for the IPP projects includes the IRS cost and costs for all COIF identified in the project respective facility study reports, including costs for the extension form the point of interconnection (POI) to the grid connection point. Costs for line extensions are dependent on the distance between a project facility's POI and grid connection point. The total interconnection costs of interconnected projects vary between $1.4 million to $12.6 million.

Figure 5-4: Interconnection Cost (Actual) of IPP Projects interconnected from 2015-2022

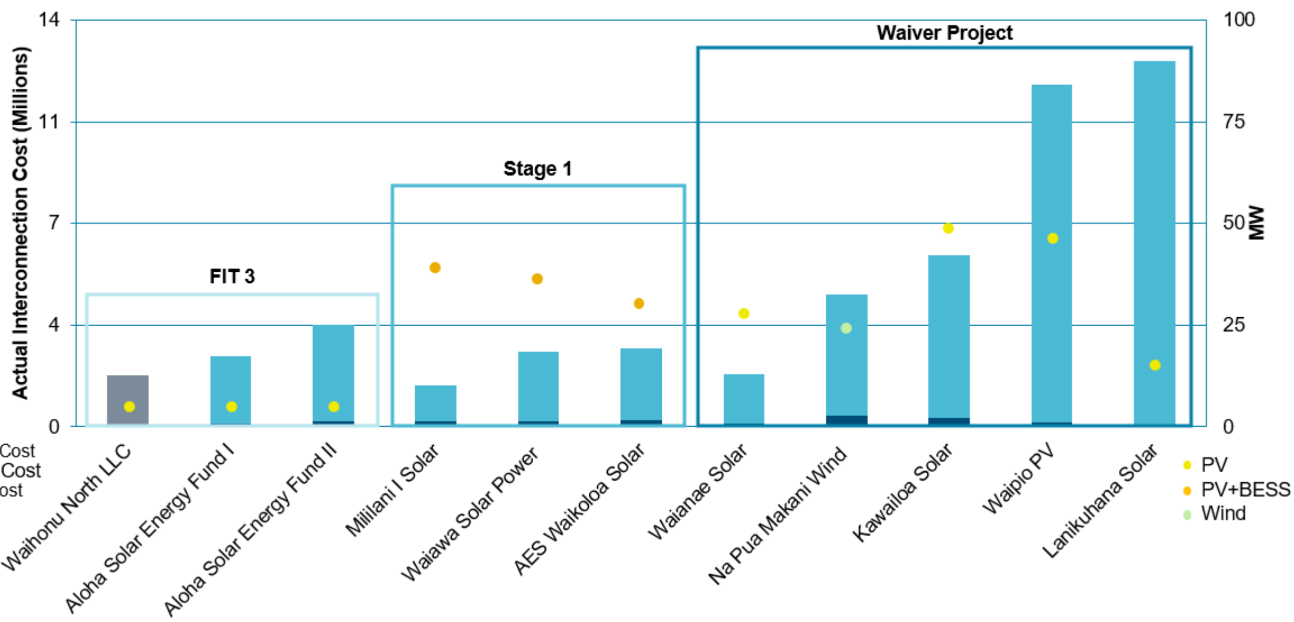
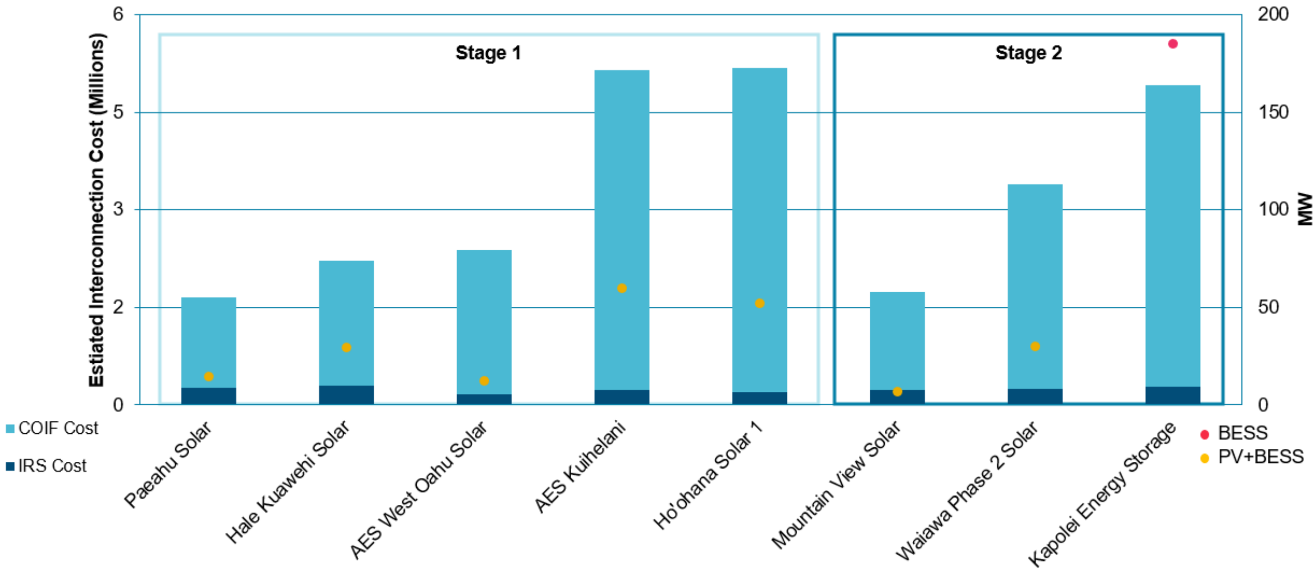


Figure 5-5 indicates estimated interconnection costs of Stage 1 and 2 RFP projects that are currently under development is between $1.4 million and $5.2 million. However, *Figure 5-5* projects still remain in the development phase and do not reflect the actual final costs or any of the IPP projects shown. All Stage 2 project reported costs include a fee used by the Companies to complete the SIS and FS, as well as any re-studies triggered by changes made to a project by the developer. For the Stage 1 and 2 RFP interconnection processes, projects are studied in clusters, which allows for the grid upgrade costs to be allocated amongst

[65] PA defines Waiver projects as the projects procured outside of Companies' structured RFP process.

all interconnection requests within the group. Lanikuhana Solar and Waipio PV interconnected at the 138 kV level which may account for the other project costs being less than half in comparison.

Figure 5-5: Interconnection Cost (Estimated) of IPP Currently Under-development [66]



As a general trend, the total costs for each of the Stage 1 and 2 projects are somewhat dependent on the total nameplate rating of each generation facility. Larger sized projects are more likely to cause greater impacts to the grid as determined via the SIS, and therefore require more scope in terms of interconnection facilities to safely export generation onto the grid. Most of the projects captured in *Figure 5-4 and Figure 5-5* had actual interconnection costs of less than $7 million, except for Waipio PV ($11.8 million) and Lanikuhana Solar ($12.6 million). Both projects interconnected at the 138 kV level, which required more expensive transmission equipment for interconnection facilities, due to the higher interconnection voltage level. All other projects accounted for in *Figure* 5-4 interconnected at the 46 kV level or below.

5.2.2 Interconnection Timeline of IPP Renewable Projects from 2015 – 2022

Figure 5-6 and *Figure 5-7* summarize the timeliness for all IPP projects analyzed during this report's study period, including projects that have already reached commercial operations. For projects currently interconnected, the average time to interconnect for those procured via the Stage 1 RFP is over 46 months as show in *Figure 5-6*. *Figure 5-7* compares the timeline of under development projects based on estimated guaranteed commercial operation dates (GCODs) estimated during the PPA approval and anticipated COD based on the recent monthly status reports. All the underdevelopment projects have longer timeline based on the current GCODs than what was originally estimated. In other words, all under development projects have missed the original GCOD timeline for various reasons including, but not limited to, equipment procurement, supply chain issues exacerbated due to the COVID-19 global pandemic, and most recently the devastating fires on Maui. Revised GCODs are present in *Table 5-11*.

[66] The figure does not include the estimated interconnection cost of Kupono solar that was recently approved by the Commission. The Companies mentioned that the estimated cost information will be available in 2023.

Figure 5-6: Timeline (PPA to COD) of Projects Interconnected from 2015-2022

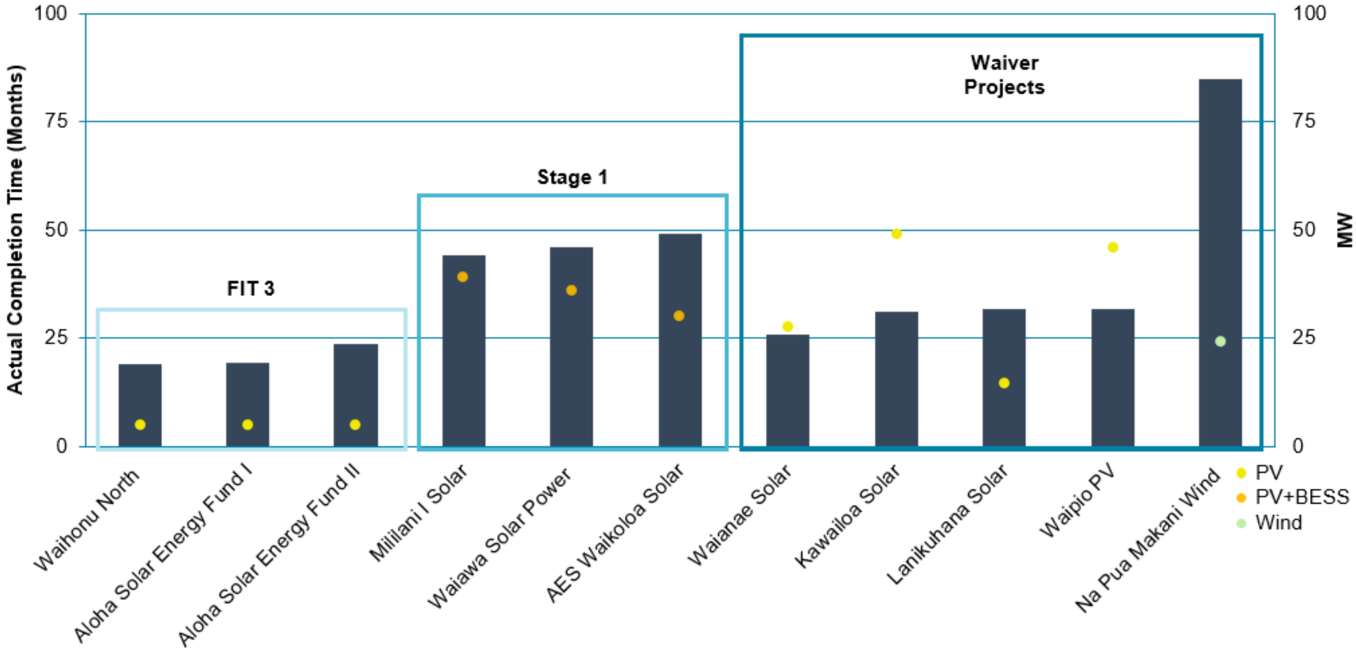
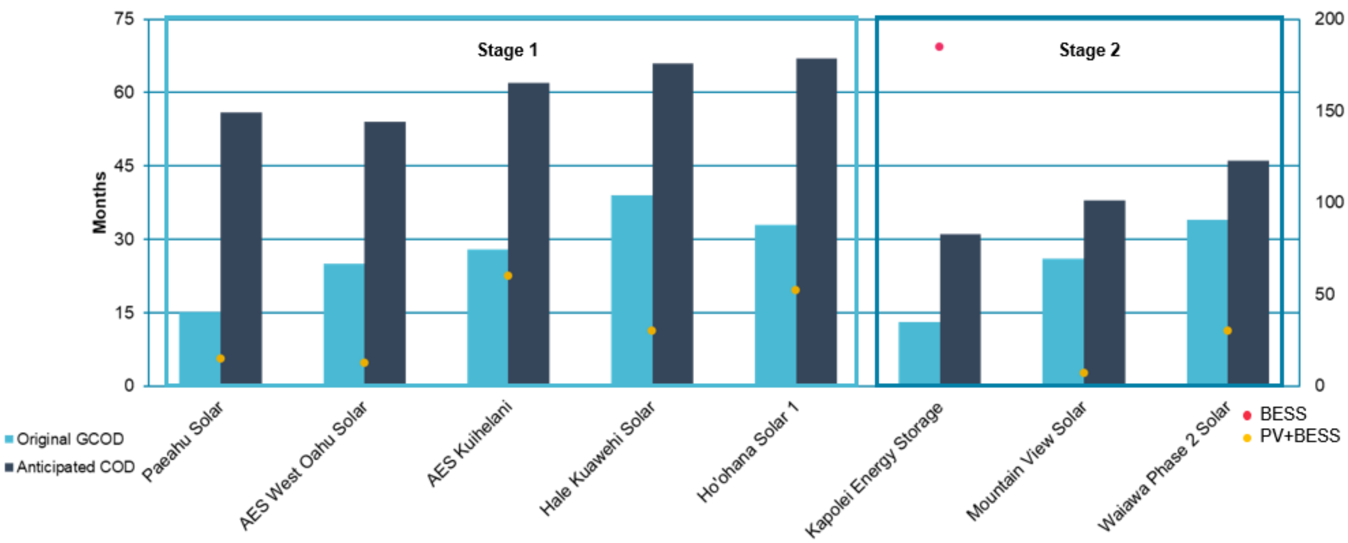


Figure 5-7: Timeline (PPA to to-date) of Under-development Projects



5.2.3 Interconnection Timeline of CBRE Projects from 2015 – 2022

Figure 5-9 shows the interconnection timeline associated with CBRE projects. The average timeline of CBRE projects that have interconnected to the Companies' system is 5 months. Note that the two interconnected CBRE projects are smaller in size as compared with the CBRE projects currently under development. The average construction timeline of four CBRE projects that are currently in development is now 19 months.

Figure 5-8: All CBRE Projects by Size

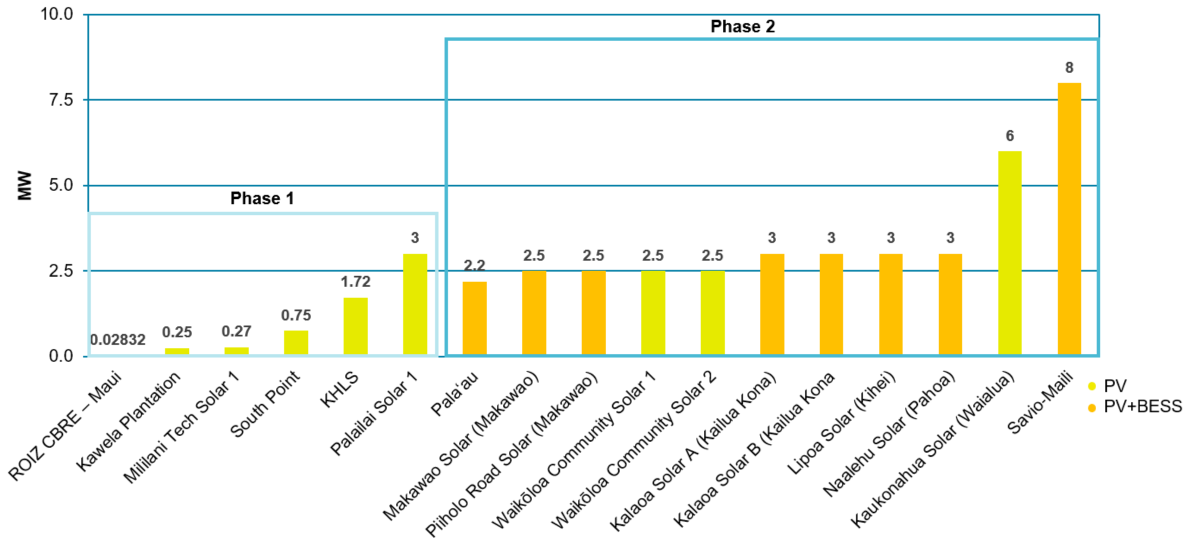
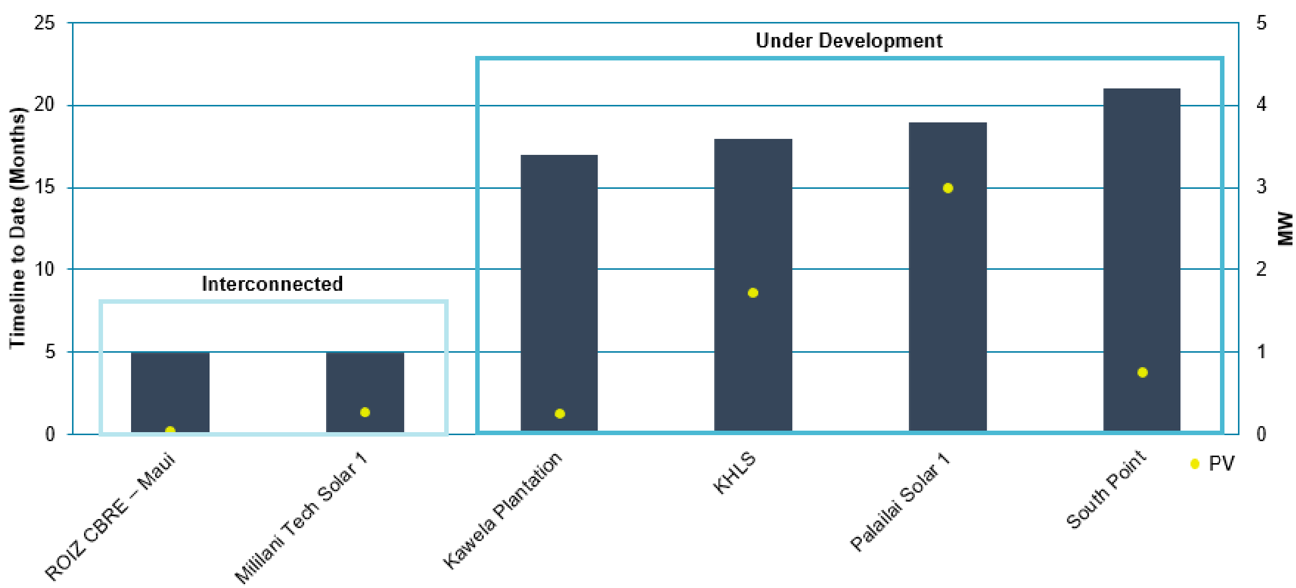


Figure 5-9: Timeline of CBRE Phase 1 Projects



The remaining CBRE projects' status shown in *Figure 5-8*, but not in *Figure 5-9* are below:

- Kaukonahua Solar (Waialua) – IRS anticipated to be completed by Company in March 2024 with an additional month anticipated for developer review and acceptance.
- Makawao Solar (Makawao) – TBD, developer models have not yet been accepted.
- Piiholo Road Solar (Makawao) – TBD, developer models have not yet been accepted.
- Lipoa Solar (Kihei) – TBD, developer models have not yet been accepted.
- Pala'au – TBD, developer models have not yet been accepted.
- Kalaoa Solar A (Kailua Kona) – TBD, developer models have not yet been accepted.
- Kalaoa Solar B (Kailua Kona – TBD, developer models have not yet been accepted.
- Naalehu Solar (Pahoa) – TBD, developer models have not yet been accepted.

- Waikōloa Community Solar 1 – No IRS Letter Agreement has been executed to date; models and funding have not been provided by the Developer.
- Waikōloa Community Solar 2 – No IRS Letter Agreement has been executed to date; models and funding have not been provided by the Developer.

5.2.4 Interconnection and Metrics of Self-build projects

During the seven-year study period, the Companies constructed one self-build project (West Loch Solar) that met the criteria outlined in Act 201.[67] There are two additional self-build projects (Keahole BESS and Waena BESS) currently pending regulatory approval by the Commission and may be developed in the future; however, the Companies requested a suspension of the review of the Keahole BESS project.[68] *Table 5-11* includes comprehensive summaries of these three self-build projects.

West Loch Solar One is a 20 MW solar farm and has been commercially operating since November 19, 2019. It interconnects into the West Loch 46kV Substation. The estimated costs for this project were $7.9 million ($395,000 per MW). The Study Team reviewed the actual costs of the project; however, the actual costs for this project are not publicly available and therefore were not included in this report. For self-build projects, the Companies do not report categorized costs for the IRS and costs for facility upgrades/construction, as they do for IPP projects.

Moreover, the total interconnection costs for self-build projects do not directly compare with the total costs associated with IPP built projects; this makes it challenging to compare the per-unit interconnection cost of self-build vs IPP-built projects. The actual interconnection upgrade costs reported for the self-build projects includes both costs of COIF and costs of SOIF. For IPP built projects, COIFs are paid for by non-utility entities – consistent with the utility's standards and requirements – whereas SOIFs are paid for by non-utility entities and typically not disclosed to the utility. Therefore, the Companies are only able to report actual COIF costs for work the Companies performed associated with IPP built projects. Costs for self-build projects are not subject to a true-up; however, the Companies do keep track of materials and labor throughout the process to account for actual costs.

Table 5-11: Project and associated interconnection related Information of Self-Build projects

Description	West Loch Solar One	Keahole Battery Energy Storage	Waena Battery Energy Storage
Tech Type	PV	BESS	BESS
Size	20 MW	12MW/12MWh	40MW/160MWh
Interconnecting Island	Oahu	Hawaii	Maui
Interconnection Voltage	46 kV	69 kV	69 kV
Point of Interconnection	WL Solar Substation	Keahole Generating Station	Waena Switchyard
Distance to POI	100 ft	Same location	Same location
Procurement Method	Waiver Project	Stage 2 RFP	Stage 2 RFP
Current Status	Interconnected	Company Requested Suspension of Review	Under Commission Review

[67] Please note that Act 201 mandated the study to include interconnection issues encountered for renewable generation projects greater than five megawatts and any community-based renewable energy (CBRE) generation projects of any megawatt size from investor-owned utilities and municipalities that serve counties with a population of more than one hundred thousand.

[68] Hawaiian Electric filed a letter in Docket No. 2020-0127 requesting a suspension of review of the Keahole BESS on November 15, 2023.

Commercial Operation Date (COD)	11/19/2019	n/a	n/a
Interconnection Time from PPA to COD	29 months	n/a	n/a
Interconnection Cost	$7.9 million (Estimated)	n/a	n/a

5.3 Interconnection Challenges and Delays in Stage 1 and Stage 2 RFP Projects

The Companies use a three-color system to denote the status of each project currently under development, and to indicate whether they believe a project could be in danger of missing its GCOD. *Table 5-12* contains a summary of each IPP project currently under development, along with their respective status assigned by the Companies in the September 2023 report to the Commission. Most projects are currently assigned a 'red' status, meaning that they are expected to miss their current GCOD, with most delays averaging about six months. The primary reason for projects missing their GCOD relates to the procurement of equipment, and several projects on Maui requesting an extension due to Force Majeure. Equipment delays impacting procurement timelines were primarily a result of disruptions to the global supply chain caused by the COVID-19 pandemic. As a result, the developers declared Force Majeure, required PPA amendments to increase price, and extended GCOD to remain viable. Some projects could not overcome these challenges and did not continue to be developed. Other issues impacting GCOD are the permitting of facilities, as well as technical issues with the IPP proposals.

Table 5-12 also includes the original GCOD stated in the PPA originally approved by the Commission for each project. The CBRE projects were executed via Standard Form contracts which, by tariff, have 18 months from contract execution to reach commercial operations, with multiple opportunities to extend the time to completion up to 90 days for "good cause".[69] If CBRE projects have achieved "substantial progress" in construction by the 18-month completion deadline, then projects have up to 6 months from the original commercial operations deadline to complete the project; however, a late fee shall be incurred.[70] One CBRE project is seeking a formal dispute after facing termination for failing to achieve the substantial progress milestone.

Table 5-12: Summary of Projects Under Development as of 11/15/23[71]

Project	Status[72]	PPA Approved Date	Original GCOD[73]	Revised (Current) GCOD[74]	Anticipated COD[75]	Delay Reason Summary
Stage 1 Projects						
AES Kuihelani	●	3/25/2019	7/20/2021	10/27/2023	5/29/2024	Originally there were delays in completion of seller's engineering drawings and supply chain issues.

[69] CBRE Phase 1 Program Tariff defines "good cause" as when extraordinary circumstances exist for which CBRE developers must request extensions and the Companies or the IO may each unilaterally approve.
[70] CBRE Phase 1 Program Tariff defines "substantial progress" as having achieved all of the following: (1) Installed all of the PV System foundation, (2) Has a permanent access road to the project facility, and (3) Has a permanent fence surrounding the project facility.
[71] The following information comes from a monthly report the Companies must submit to the PUC accessed.
[72] The reports also use a three-colored system to track the status of the overall project, and whether it is on target to meet the GCOD: green denotes that the project is currently on track to meet the GCOD; yellow denotes that the project is at risk for missing its GCOD; red denotes that the project is expected to miss its GCOD.
[73] Original GCOD from the Stage 1 and 2 projects' approved PPAs, some projects have an updated GCOD per their PPA amendments.
[74] Revised GCOD per October 2023 monthly report.
[75] Anticipated COD per October 2023 monthly report.

						Most recently (07/13/2023) provided notice of Force Majeure citing effects of devastating fires. 09/07/2023 Company did not believe AES provided reasonable evidence and currently awaiting additional response. Second Amendment was approved by the PUC on 10/16/23.
AES West Oahu Solar, LLC		8/21/2019	9/30/2021	1/20/2023 [76]	2/19/24	Building permits approval.
Hale Kuawehi Solar LLC		3/25/2019	6/30/2022	10/11/2024	10/11/2024	First delayed due to supply chain issues. First Amendment approved by PUC on 8/1/23. On 09/07/2023 Seller emailed Notice of Potential Force Majeure – Wildfire Events. On 09/18/2023 seller withdrew FM claims with new GCOD 10/11/2024. Developer plans to provide additional estimates of impacts and timelines.
Ho'ohana Solar 1, LLC		3/25/2019	12/31/2021	10/31/2024	10/31/2024	First delayed due to equipment procurement issues, permitting delays, and an amendment to the PPA. A third PPA amendment was approved 5/23/23 on the basis of supply chain issues and a labor shortage. On 09/08/2023 Seller provided Company with a Notice of Potential Force Majeure. On 09/11/2023, Company responded acknowledging and noting the Seller must note specific projects caused by events to be considered a Force Majeure.
Paeahu Solar LLC		1/14/2021	4/28/2022	4/28/2023	10/1/2025 [77]	Project to experience delays as part of the re-approval process of CUP/PH2 permits. Project developer did not reach settlement with intervenors in Mediation meetings which occurred during May 3 through May 27, 2022. As a result, the hearing schedule for future settlement process was provided on 08/25/22 indicating steps required for the first phase of the process between September to mid-November, including evidentiary hearing commencing on 11/28/22. The actual hearing did not commence until December 2022 and due to unforeseen circumstances has now been pushed into January 2023 by

[76] New GCOD per the Second Amendment to the PPA
[77] The seller is forecasting a Q3 2025 COD, but schedule is not officially updated yet.

						the hearings officer. Awaiting updates from the hearing officer.
Stage 2 Projects						
Kapolei Energy Storage		4/29/2021	6/1/2022	12/30/2022	12/18/2023	Primarily a result of supply chain and permit delays.
Kupono Solar		7/22/2022	6/1/2022	4/9/2024	4/9/2024	N/A
Mountain View Solar		3/25/2021	5/17/2023	5/17/2023	5/17/2024	First delayed as a result of equipment delays and substation design. On 08/16/2023 Seller delivered Force Majeure notice as a result of the Maui wildfire. Company did not accept Seller's Force Majeure explanation as a notice of Force Majeure at this time. Second Amendment was approved by the PUC on 10/30/23.
Waiawa Phase 2 Solar		12/30/2020	10/30/2023	9/1/2024	11/5/2024	Initial delays as a result equipment procurement and substation design submittal delays. Second Amendment was approved by the PUC on 8/1/23. On 8/16/2023 Seller delivered Force Majeure notice due to the Maui wildfires but Company did not accept Seller's Force Majeure explanation as a notice of Force Majeure at this time.
CBRE Projects						
KHLS		N/A	N/A	3/17/2022	06/01/2024	Company seeks to terminate project due to failure to reach critical construction milestones. Project developer seeking a formal dispute over missed milestones.
Ka Lae		N/A	N/A	6/1/2023	Unknown	Seller submitted an additional request for extension in November 2022. Seller provided notice facility was energized using off-grid generator on 9/18/23 to start commissioning and testing.
Kawela Plantation		N/A	N/A	10/19/2023	Unknown	Initial delay as a result of equipment procurement issues. Project GCOD adjusted via PUC change to construction period from 18 to 24 months with good cause 3-month extension.

After reviewing projects that were interconnected over the last seven years (from 2015 to 2022), PA has identified general issues within the different interconnection process steps that have led to delays in projects reaching their COD. The Companies noted the delays can largely be attributed to the first step in the interconnection process which involves the models submitted by developers. Specifically, the issues identified by the Companies related to model submissions that included multiple deficiencies that prevented the Companies from using the proposed facility's model in the SIS. As a result, developers needed additional time to address deficiencies with model consultants and equipment manufacturers to fix identified issues so that the model could be incorporated into the Companies' SIS. Since the system impact studies are performed for a cluster of projects, if one project model is delayed in meeting its requirements, it delays the SIS for the rest of the projects in that cluster as well.[78] Finally, the Companies note that any changes a developer may elect to incorporate to their project after completion of the SIS will likely require a re-study, that could further be impacted by any issues with the updated models needed to analyze the updated project's potential impact to the grid.

[78] All projects in Stage 1, and 2 RFPs were studied in clusters.

6 State of Hawaii Reliability Standards

The development of reliability standards in the state has been a topic of discussion for over a decade. The 27th Hawaii Legislature passed SB No. 2787 SB 2 HD 2 CD 1 in 2012 which was signed into law as Act 166 which established the Hawaii Electricity Reliability Administrator (HERA) law.[79] Contemporaneously, the Commission convened stakeholders to discuss the development of reliability standards in Docket No. 2011-0206 and a working group developed and proposed the implementation of 10 reliability standards following NERC's standard format.[80] The findings and recommendations from these efforts were continued in subsequent dockets, including various planning proceedings.[81] While Hawaiian Electric has interconnection requirements and operating performance standards in its RFP documents and PPAs, reliability standards have not been adopted nor applied systematically to monitor and plan the Companies' operations. In 2021, the State Senate passed a resolution S.R. 207 S.D.1 requesting the Commission to develop and adopt reliability standards and interconnection requirements to facilitate the timely interconnection of Utility-Scale renewable projects.[82] In December 2021, the Commission filed a report to the Legislature in response.[83] In the report, the Commission reported that it is in the process of soliciting input from qualified entities to serve in the role of HERA. Moreover, the Commission provided recommendations and proposed legislation amending Hawaii Revised Statutes (HRS) § 269-146 to ensure that the Commission has discretion in determining how the Hawaii electricity reliability surcharge should be assessed to reduce potential risks to ratepayers and that customers are not forced to bear the cost burden for the establishment of the HERA.

In March 2022, the Commission issued a Request for Information (RFI) soliciting capabilities and expertise of prospective entities interested in contracting with the Commission to serve as the HERA.[84] However, given the Companies Stage 3 RFP process was anticipated to begin in 2022 Q4 and given the complexity and length of time it would take to establish HERA, the Commission instead focused on contracting with an IE in alignment with the Stage 3 RFP process. The Commission carved out certain portions of the initial HERA scope to be executed by the role of IE; specifically, the responsibilities of the IE are similar to the scope of interconnection oversight laid out in the HERA statutes. The RFP regarding the IE role was issued on July 1, 2022. The Commission intends to assess the efficacy of the IE performing interconnection-related aspects of the HERA scope while exploring additional opportunities to perform additional aspects of the HERA scope through other workstreams.

6.1 Background and Timeline

Reliability is a necessary and multi-faceted component when evaluating the operation and oversight of an electric grid. The Federal Energy Regulatory Commission (FERC) has a role in overseeing the reliable operation of the US's electric grid. FERC certified the North American Electric Reliability Corporation (NERC) as the electric reliability organization, and NERC is responsible for developing and enforcing mandatory reliability standards. Throughout the US there are Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) which are responsible for helping to ensure regional compliance to the reliability standards.

Hawaii is unique compared to many other US states in that its electric grid is not part of a larger regional electric grid managed by an RTO or ISO. Additionally, each island within Hawaii has its own individual grid, geographically and electrically independent from the other islands. This presents unique challenges related to system reliability, especially as the state looks to add renewable resources to meet its renewable portfolio standards (RPS) goal.[85]

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[79] Act 166, SLH 2012 available at: https://www.capitol.hawaii.gov/slh/Years/SLH2012/SLH2012_Act166.pdf

[80] Of note, the working group did not reach agreement on certain key standards.

[81] These dockets include Docket Nos. 2014-0192 and 2019-0323, which investigate the interconnection standards for distributed energy resources (DERs) and Docket Nos. 2014-0183 and 2018-0165, which review the Companies planning processes, namely the Power Supply Improvement Plans and the Integrated Grid Planning (IGP) process.

[82] S.R. No. 207, S.D.1, State of Hawaii, The Senate, Thirty-First Legislature, 2021.

[83] State of Hawaii Public Utilities Commission, Report to the Legislature Pursuant to S.R. 207, S.D. 1, Filed December 2021.

[84] Request for Information, Hawaii Electricity Reliability Administrator, March 2022.

[85] Hawaii has a Renewable Portfolio Standard (RPS) goal of 100% of its electricity being from renewable sources by 2045; established in Act 97, SLH 2015.

Reliability Standards Working Group (RSWG)

The Commission discussed reliability related issues at both the transmission and distribution levels at length in the Commission's feed-in tariff investigation docket.[86] In that docket, the Companies provided a proposal to develop reliability standards for the Companies through a Reliability Standards Working Group (RSWG). The Commission approved this proposal, and a new docket was opened on September 8, 2011.[87] The Commission hired an Independent Facilitator (IF) to facilitate the RSWG which was comprised of various stakeholders including the Companies, Kauai Island Utility Cooperative, the counties, state agencies, IPPs, industry advocates, environmental advocates, and other stakeholders. The IF held its first meeting with the RSWG on July 13, 2011.

The RSWG formed several sub-groups to explore different topics. These sub-groups were focused on:

- Gap Analysis
- Integrated Resource Planning
- Reliability Definitions and Metrics
- Reliability Standards Development (RSDG)
- Minimum Load and Curtailments
- Photovoltaics
- Demand Side Options

The Commission provided guidance to the RSWG through an order[88] which also directed the Companies to file monthly reliability reports. The IF and RSWG held their final meeting on January 24, 2013. The IF filed the final work product of the RSWG on March 25, 2013.[89] Through the RSWG, the RSDG sub-group used then-current utility information to create reliability standards tailored to Hawaii and based on NERC's standard format. The RSDG developed ten reliability standards which were presented in the RSWG's final work product. The reliability standards developed were:

- Real Power Balancing Control Performance;
- Disturbance Control Performance;
- Planning Resource Adequacy Analysis, Assessment and Documentation;
- Development and Reporting of Steady State System Models and Simulations;
- Development and Reporting of Dynamic System Models and Simulations;
- Actual and Forecast Demands, Net Energy for Load, Controllable DSM and Distributed Generation;
- Verification and Data Reporting of Generator Real and Reactive Power Capability and other Reactive Power Sources;
- Verification of Models and Data for Generator / Transmission Equipment Excitation System or Plant Volt / Var Control System;
- Verification of Models and Data for Governor and Load Control or Active Power / Frequency Control;
- Under-frequency Load Shedding.

The Commission issued its ruling related to the RSWG's final work product and other reliability matters on April 28, 2014.[90] In its ruling, the Commission decided to further evaluate proposed reliability standards in

[86] Docket No. 2008-0273.

[87] Docket No. 2011-0206, Instituting a Proceeding to Investigate the Implementation of Reliability Standards for the Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited.

[88] Commission Order No. 30371, dated May 4, 2012

[89] *Reliability Standards Working Group Independent Facilitator's Submittal, Final Report and Certificate of Service,* Docket No. 2011-0206 (Mar. 17, 2013), Filed with the Commission on March 25, 2013.

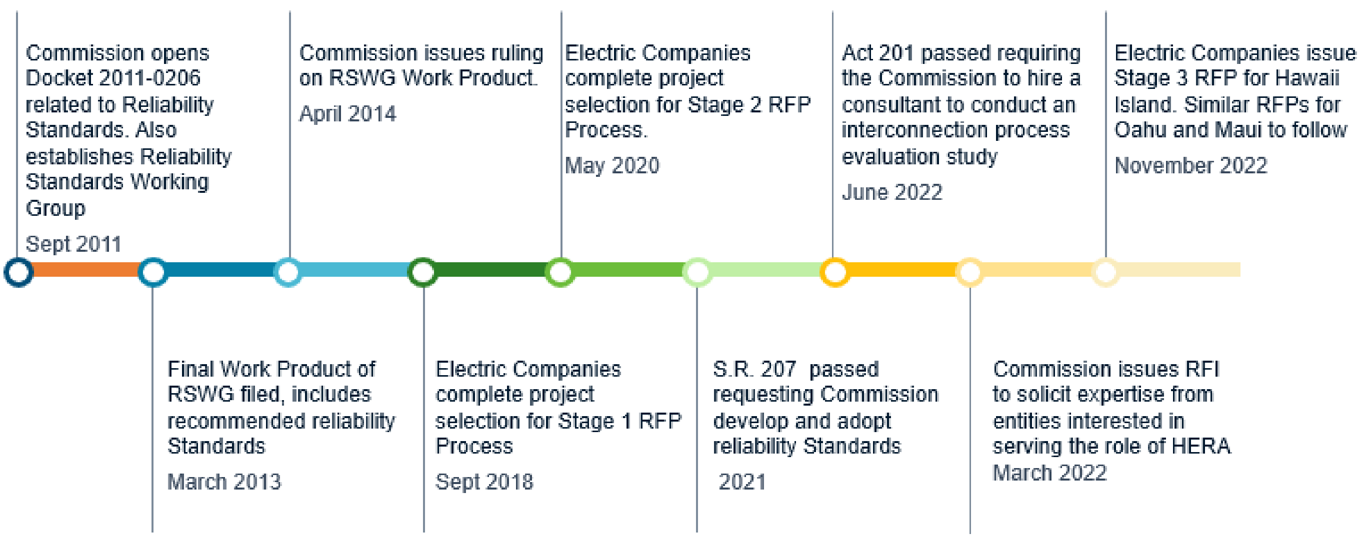
[90] *Instituting a Proceeding to Investigate the Implementation of Reliability Standards for the Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, Commission Order No. 32053,* Docket No. 2011-0206, (Apr. 28, 2014)

related dockets. These dockets include Docket Nos. 2014-0192 and 2019-0323, which investigate the interconnection standards for distributed energy resources (DERs) and Docket Nos. 2014-0183 and 2018-0165, which review the Companies planning processes, namely the Power Supply Improvement Plans and the IGP process. The Companies have reported reliability metrics that reflect some of the standards in the RSWG report and have established interconnection standards and requirements that reflect other standards found in the RSWG report which have been incorporated into PPAs, RFP procedures, and other tariffs governing interconnection. Other standards from the RSWG report are provided through reported metrics in various dockets. The reliability-related metrics and interconnection-related requirements have been addressed in the relevant reports and initiatives. Also, new standards are being developed and introduced as industry standards are inherently an evolving process.

The Companies have recently held multiple RFPs in recent years to procure more renewable resources, with project selections for the Stage 1 RFPs being completed on September 17, 2018, and project selections for the Stage 2 RFPs being completed on May 8, 2020. However, due to delays related to the COVID 19 pandemic, supply chain issues, permitting delays, and in some cases interconnection issues, renewable projects that the Companies have procured through its Stage 1 and 2 RFP processes have been delayed in reaching their COD. As such, both the Hawaii State legislature and the Commission have shared concerns regarding interconnection and project delays and their possible impacts on reliability.

In 2021, the Hawaii Senate passed S.R. 207, SD1[91] requesting the Commission to establish reliability standards and interconnection requirements in order to help facilitate timelier interconnection of Utility-Scale renewable energy projects.

Figure 6-1: Timeline of Activities Related to the Establishment of Reliability Standards



6.2 Reliability Standards

The Commission monitors several reliability metrics related to the utility's system performance and approves all interconnection requirements and procedures utilized by the utility in its RFP and interconnection processes.[92] Increasingly with each subsequent RFP, non-utility stakeholders' experience in the interconnection process has informed interconnection requirements. Stakeholder input and involvement in the IGP process, for which the utility recently filed its Final Report,[93] has also supported improvements to interconnection requirements.

The Commission requires the Companies to file several reports relating to service reliability. These reports include monthly reliability reports on system frequency control performance, significant system events, and

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[91] S.R. No. 207, S.D.1, State of Hawaii, The Senate, Thirty-First Legislature, 2021.

[92] The Commission reviews reliability metrics submitted by Hawaiian Electric in multiple reports, including key performance and scorecards published on Hawaiian Electric's website and reports filed with the Commission in docketed and non-docketed proceedings. Commission approval is required for updates to tariffs and rules that contain interconnection requirements and for procurements, which contain additional requirements and procedures for the interconnection process.

[93] The Final Report from Hawaiian Electric's Integrated Grid Planning process is available at: https://hawaiipowered.com/igpreport/.

mitigations taken[94] and quarterly reports on service reliability outage metrics.[95] In addition, Adequacy of Supply Reports[96] which are used to monitor the ability of the utilities to reliably serve their service territories. These reports are filed annually and detail the Companies' plan to meet their reliability planning criteria, accounting for existing resources, procurement of new resources, and retirement of aging fossil fuel resources to meet the State's RPS goals. Additionally, the Companies file reports on curtailment of non-dispatchable renewable resources.[97]

In 2021, the Commission established multiple trackers and incentives for the utility's performance related to reliability and power supply under the PBR framework, such as the T&D Reliability Performance Incentive Mechanism (PIM), which awards financial incentives for achieving target levels of common reliability metrics measuring the duration and frequency of service interruptions.[98] In 2022, the Commission updated the PBR Framework to incentivize timely interconnection studies, because both the utility and developers have historically caused delays in this area, and established a Generation Reliability PIM based on SAIDI and SAIFI metrics for generation-related service interruptions.[99] The Commission intends to continue to use the PBR framework to address concerns over interconnection costs in conjunction with policy changes being evaluated related to interconnection costs in the RFP dockets.

The Commission also investigated the use of reliability metrics in the utility's plans for procuring new resources in the IGP docket.[100] Specifically, the utility evaluated various reliability metrics to measure and determine the amount of new firm renewable resources to target in future RFPs. Due to potential ratepayer impacts of these new firm resources, the Commission is evaluating the reliability standards used in other jurisdictions to ensure that the Companies procure the appropriate amount of new firm resources to balance reliability and costs. The Commission is continuing to explore establishing a reliability standard or multiple standards to use in the procurement processes for new resources. For example, the Commission is continuing work with the Companies to incorporate national/international standards in RFP requirements such as the applicable components of Institute of Electrical and Electronic Engineers' standard 2800-2022 which among other things includes several performance requirements to improve system reliability.

6.3 Hawaii Electric Reliability Administrator

In 2012, Act 166 was signed into law which authorized the Commission to establish the HERA[101] and perform different oversight functions related to electric reliability. As discussed above, the final RSWG report, via the work of the RSDG sub-group, assessed various aspects of the reliability issues. The RSDG kept in consideration the fact that any approved reliability standards would likely transfer to the HERA, when drafting the new guidelines under the RSWG. In Order No. 32053, the Commission stated that several important components of the RSWG's work product, including the establishment of reliability standards, are closely linked with the HERA and given the Commission's broad authority granted under the statutes, the Commission

[94] Hawaiian Electric files these monthly reports in Docket No. 2011-0206, as well as on Hawaiian Electric's website, available at: https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/renewable-energy/rswg-monthly-reports.

[95] The quarterly reports are available on Hawaiian Electric's website, available at: https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/service-reliability .

[96] The annual Adequacy of Supply reports are available at: https://puc.hawaii.gov/reports/energy-reports/adequacy-of-supply/.

[97] Hawaiian Electric files monthly reports in Docket No. 2011-0206, as well as on Hawaiian Electric's website, available at: https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/renewable-energy/rswg-monthly-reports.

[98] See Decision & Order No. 37787, filed in Docket No. 2018-0088 on May 17, 2021, wherein the Commission approved a suite of performance incentive mechanisms and a portfolio of scorecards and reported metrics to incentivize, track, and measure utility performance.

[99] See Decision & Order No. 38429, filed in Docket No. 2018-0088 on June 17, 2023, wherein the Commission established a suite of additional performance incentive mechanisms, including a mechanism related to interconnection study timeliness.

[100] Following Hawaiian Electric's responses to the PUC-HECO-IR-54 and PUC-HECO-IR-57, filed in Docket No. 2017-0352 on June 30, 2023, and August 28, 2023, respectively, Commission Staff directed the Independent Observer and Hawaiian Electric to conduct a supplemental reliability analysis of the Stage 3 RFP portfolio of proposals to assess the reliability of selecting different levels of firm resources.

[101] Hawaii Revised Statutes (HRS), §269-141 through §269-149. Originally passed in 2012 as Act 166, Session Laws of Hawaii 2012.

decided to “initiate its own framework addressing the purpose, scope, and organizational structure of the HERA,” and noted that the framework development was underway.[102]

In December 2021, the Commission filed a report to the Legislature in response to the S.R. 207 SD1 resolution that requested the Commission to submit a report regarding various matters including the HERA.[103] In the report, the Commission reported that it is in the process of soliciting input from qualified entities to serve in the role of the HERA. Moreover, the Commission provided recommendations and proposed legislation amending section 269-146, Hawaii Revised Statutes, to ensure that the Commission has discretion in determining how the Hawaii electricity reliability surcharge should be assessed to reduce potential risks to ratepayers and that customers are not forced to bear the cost burden for the establishment of the HERA.

In February 2022, continuing its effort towards the establishment of the HERA, the Commission issued an RFI requesting capabilities and expertise of prospective entities interested in contracting with the Commission to serve as the HERA.[104] In the RFI, the Commission mentioned that the objective of the HERA is to “ensure the reliable design and operation of the Hawaii’s electric utility grid on a continuous basis, with an initial focus on the systems operated by Hawaiian Electric. The Commission intended the HERA, under its authority, to establish effective and transparent Reliability Standards and oversee interconnection-related matters affecting Hawaii’s electric utility grid, with the goal of maintaining safe and efficient grid operations for all users. Pursuant to HRS § 269-142, the HERA’s scope also includes non-utility entities that operate on electric systems (i.e., independent power providers, ancillary service providers, etc.).

Given the Companies’ Stage 3 RFP process began in late 2022 and given the complexity and length of time it would take to establish the HERA, the Commission prioritized the highest impact functions related to interconnection and contracted with an IE in alignment with the Stage 3 RFP process. The Commission carved out some portions of the initial HERA scope to be applied to the role of IE; specifically, the responsibilities of the IE are similar to the scope of interconnection oversight laid out in the HERA statutes. The RFP regarding the IE role for Stage 3 RFP was issued on July 1, 2022.

As of October 2023, the Commission has hired entities to serve in the IE role to assist in both the Stage 3 RFP process and CBRE Phase 1 and 2 process. The Commission also intends to continue to utilize the IE in future Hawaiian Electric Company RFPs based on the successes of the IE in providing technical oversight in the RFP bid evaluation, engaging in interconnection-related dispute resolution, and advising the Commission on technical matters related to Hawaiian Electric’s RFPs, including improvements for future RFPs. At this time, the Commission believes that hiring entities to serve in the IE role is a more cost-effective method of overseeing Hawaiian Electric’s practices related to procuring new energy resources and maintaining reliability, while exploring additional ways to address the additional aspects of the HERA scope through modifications to the Companies’ planning proceedings, through revisions to the PBR framework, and through additional contracts for entities with expertise in implementing reliability standards. The Commission’s intent is to address the components of the HERA in the most cost-effective manner in order to avoid leveraging the electric reliability surcharge and impacting ratepayers, while ensuring that reliability is adequately addressed across Hawaiian Electric’s service territories.

Stakeholder Insights

During the stakeholder interviews, detailed in Section 4, the Study Team found that 3 of the 4 utility-scale developers in the Stage 3 RFP were not aware of the role of the Independent Engineer. In light of this, the Commission should take steps to raise awareness about the Independent Engineer and their role in the RFP and interconnection process.

[102] *Instituting a Proceeding to Investigate the Implementation of Reliability Standards for the Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, Commission Order No. 32053*, Docket No. 2011-0206 (Apr. 28, 2014)

[103] State of Hawaii Public Utilities Commission, Report to the Legislature Pursuant to S.R. 207, S.D. 1, Filed December 2021.

[104] Request for Information, Hawaii Electricity Reliability Administrator, February 2022.

7 Findings and Recommendations

This section includes the Study Team's key findings and recommendations for process improvements, per the guidelines set forth in Act 201. We organized our findings and recommendation in topical areas that are consistent with Section 3 (see Sections 7.1 through 7.6).

7.1 State of Hawaii Interconnection Policy

Findings

State of Hawaii Interconnection Regulatory Policy

- The State's existing regulatory policy is covered by a combination of decisions and orders addressed to specific interconnection issues within the State, as well as General Order No. 7. As General Order No. 7 addresses a broad range of topics related to electric service, it does not contain expansive regulations related strictly to interconnection, but instead regulates specific aspects that are related to, or are components of, the interconnection process.
- All of the Companies' requirements related to interconnection are under the jurisdiction of the Commission; the Commission can exert influence over the Companies' internal processes, specifically through the Commission's regulatory authority.
- In addition to General Order No. 7, there are additional requirements and procedures for construction of high-voltage transmission equipment that is within the jurisdiction of the Commission; this includes, but is not limited to, equipment used to facilitate the interconnection of generation facilities to the electric utility's transmission grid.[105] Additionally, recent state law revised these requirements, stating that the utility does not need Commission approval if the transmission equipment is to be built underground, the entire cost of the underground upgrade is paid for by an entity other than the utility, and the utility provides a report, prior to construction, detailing the project and the funding source.[106]
- The Commission is also required to conduct a public hearing whenever the utility plans to build a new 46kV or greater transmission line above ground and through a residential area.[107]

Recommendations

- The Study Team did not find substantial evidence or insights to signal recommendations for the State's interconnection policy or regulatory and/or statutory modifications.

7.2 The Companies' Interconnection Process

Findings

The Companies' Interconnection Requirements

- Each Company has a set of tariffs that regulate the interconnection process: Rule No. 14 and Rule No. 19. The tariffs are under the Commission's jurisdiction, therefore, any language updates proposed by the Companies are subject to its approval.
- The Rule No. 19 includes interconnection guidelines and requirements for projects interconnecting to the Companies' system issued pursuant to a RFP process. However, it contains very little information regarding the expectations for all stakeholders during the interconnection process, as well as technical requirements for facilities to interconnect. Furthermore, Rule No. 19 may be superseded by provisions in a Commission-approved RFP process, creating additional uncertainty as to which documents and requirements take precedence for developers who must adhere to such requirements.
- Rule No. 14 provides interconnection guidelines and requirements for projects interconnecting at the Distribution level (25 kV and below on Oahu, and 12 kV and below on the other islands). The tariff is inclusive of the expectations for independent developers, as well as the Companies, for the entire

[105] Hawaii Revised Statutes (HRS), §269-27.6.
[106] See Hawaii Revised Statutes (HRS), §269-27.6(d), as revised by Act 65, Session law 2021.
[107] HRS §269-27.5.

interconnection process. The tariff also contains detailed technical requirements for facilities to interconnect successfully to the distribution system.

- Unlike Rule No. 14, Rule No. 19 does not contain technical details for interconnection so IPPs must refer to the relevant RFP to find meaningful requirements for interconnecting to the sub-transmission or transmission systems.
- The Companies currently do not have a standardized method to share electric system and POI information to the bidders that are interested in participating in the RFP process.
- For Stage 3 RFP process, Companies required all bids to provide interconnection and technical related data with the initial bid submission. The Companies requested numerous technical data related with interconnection. These are outlined in Appendix B Attachment 2b of the Stage 3 RFP document.[108] This process is set up as a single step which collects all possible technical information to not only perform interconnection studies, but also to design, procure equipment and fully construct and operate the plant from all bidders.

Interconnection Process

- The renewable project proposals are first procured through the RFP process, and the bids are evaluated through a set framework outlined in the Stage-specific RFP document. For Stages 1 and 2 RFP projects, once a bid has been selected by the Company, the Company and the developers will move into the interconnection study phase. This runs concurrently with execution of the PPA prior to submission to the Commission for approval of the PPA and for the construction of the lines needed to connect the project to the grid.
- For Stage 3 RFP projects, the Company will complete the IRS prior to executing the PPA with the developer, so that all interconnection-related upgrades are known at the time of filing the PPA with the Commission for approval.
- The SIS will be completed to evaluate the effects of the proposed projects interconnecting to the system. The results will be used to identify any required system upgrades necessary for the projects to safely interconnect to the grid, as part of the subsequent facility study.
- Once the developers and Companies agree to terms regarding the construction and financing of the identified interconnection facilities, the PPA will be amended to reflect the interconnection upgrades. At the time of the finalization of the FS, developers may elect to terminate their PPA if they determine the interconnection upgrade costs to be prohibitively expensive.
- After the PPA and Interconnection Requirements Amendment have been executed, the interconnection facilities will be constructed by the responsible party in time to meet the deadlines established in the PPA. Upon completion of construction and the commissioning of the project and its new facilities for interconnection, the project will be granted permission to be in commercial operation by the Companies, and the actual costs will be true-ed up, and subsequently reconciled with the developer.

Interconnection Timeline and Metrics

- The timelines for each step in the interconnection process is set forth in the Island-specific RFP document; in each successive Stage RFP, the Companies have worked to optimize their interconnection processes to reduce the time of completion for their specific action items and milestones.
- There are also set timeframes for the developer-specific milestones as well, and those time limits are reported in the overall timeline completion metrics for each project.
- Based on the Company's September 2023 report[109] regarding the status of Stage 1 and Stage 2 RFP projects, all Stage 1 and 2 RFP projects that are currently being developed will miss their original GCODs included in the PPAs approved by the Commission. Only Hale Kuawehi Solar, Ho'ohana Solar 1, and Kupono Solar are expected to meet the revised GCODs. All other remaining projects' anticipated CODs are later than their revised GCODs.

[108] For example, please refer Appendix B, Attachment 2a of Hawaii Island RFP via this source: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/selling_power_to_the_utility/competitive_bidding/20230228_hawaii_stage_3/20230322_appx_b_proposers_resp_pkg.pdf

[109] Docket No. 2021-0024

- Based on the discussion with the Companies, most of the interconnection delays have been caused by technical documentation related issues provided prior to the start of the SIS coupled with Covid-related and other persisting supply chain issues.

Interconnection Process for Self-Build Projects

Self-Build Projects

- The Companies file monthly project status reports of self-build projects to the Commission. The monthly reports include the projects' status regarding: the IRS; engineering and design; permitting and land rights; equipment procurement and construction; and commissioning of the project and interconnection facilities. However, the Companies do not publicly include detailed interconnection related metrics for the self-build projects in the public docket that is currently maintained for the IPP projects related to IPP Interconnection Reported Metrics[110] .
- The total interconnection costs associated with the self-build projects are not categorized by COIF and SOIF costs, as usually done for the IPP projects, since the Companies own all aspects of those facilities for their own projects. They also do not report costs for the efforts related to the IRS for self-build projects, as those are paid by the same entity – the Companies themselves.
- The IRS process for self-build projects is identical to that for IPP projects; the only difference is the lack of any PPA negotiations, as the Companies will procure their own the facilities and perform the operations and maintenance to generate power. The Companies do report the IRS for self-build projects to the Commission.
- The Companies may request to recover costs for self-build projects under the performance-based regulation framework. Previously, Companies recovered costs through general rate cases and separate cost-recovery mechanisms. The costs for self-build projects are also subject to approval by the Commission via a 'Request to Recover Capital', per General Order No. 7, if costs are above a certain threshold.

Recommendations

Interconnection Requirements

- The Companies should review interconnection related tariff/rules and revise, if necessary, to provide technical clarity in terms of interconnection requirements.
  - For example, expand and include technical interconnection requirements into Rule No. 19, or into a new generic transmission and sub-transmission interconnection tariff, to capture all the requirements in one document, similar to how Rule No. 14 captures the technical interconnection requirements for connection on the distribution level.
- The Reliability Standards Working Group's (RSWG) Report also recommended that the interconnection tariffs – including Rule No. 14 and Rule No. 19 – be revised to be more consistent with each other and inclusive of the overall process requirements. The revisions will provide project developers clarity regarding interconnection requirements, and which take precedence.
- The Commission should perform an interconnection procedures and cost benchmark study to understand renewable energy integration metrics scoring criteria and opportunities to streamline processes from other jurisdictions. Such benchmarks could be obtained from jurisdictions that have similar regulation, decarbonization, or landscape characteristics as Hawaii.

Interconnection Process

- The Companies should consider providing adequate interconnection related information to the bidders in an easily accessible way during the pre-bid period via a templatized "Pre-Application" report at the interested POI/substation. The "Pre-Application" report for developers could include helpful information for planning interconnection designs such as POI/substations within the area, peak loads, existing generation and pending installs, total available capacity, voltage and circuitry, regulation equipment and communication devices, protective devices, any limitations or constraints, etc.

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[110] Hawaiian Electric, Interconnection Experience, https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/interconnection-experience.

- The Companies should consider using a multi-step approach to request interconnection data from the bidders. The multi-step approach will help streamline and enhance the Companies' interconnection process and provide value by reducing the cost of bid preparations, thus encouraging submission of more bids in future RFPs. The Companies could organize interconnection data collection such that only the absolute minimum required data is collected first and more detailed information is collected when the winning bid proceeds to construction phase.

Interconnection Cost for Self-build projects

- The Companies should develop comparable interconnection cost metrics for self-build and IPP-built projects so that interconnection costs can be directly compared. The Companies should track the total interconnection cost of the self-build projects separately by IRS, COIF and SOIF costs so that appropriate components can be compared with the IPP-built projects.

7.3 Interconnection Cost and Regulation

Findings

- Currently, the cost of most elements regarding the interconnection process are not rate-based, and instead are the responsibility of the generation facility developers. Specifically, any costs associated with the project's generating facility, as well as most grid upgrade costs are the responsibility of the developer.
- The cost recovery for self-build projects is subject to approval by the Commission via a 'Request to Recover Capital', per General Order No. 7, if costs are above a certain threshold.[111] The Commission also approves the means of cost recovery, which changed after the PBR framework took effect on June 1, 2021. Under PBR, the Companies may request to recover capital and O&M costs for approved self-build projects via the EPRM. Recovery is limited to actual costs and is often capped by the Commission.
- The interconnection cost of each project is determined by facilities identified in the FS that are necessary to interconnect the project to the electric utility's grid. The total interconnection cost includes three major cost components: the IRS costs, COIF costs, and SOIF costs.
- For IPP built projects, COIFs are paid for by non-utility entities– consistent with the utility's standards and requirements. SOIFs are paid for by non-utility entities, but typically are not disclosed to the utility. Therefore, the Companies are only able to report actual COIF costs for work the Companies performed associated with IPP built projects. Performance-Based Regulation (PBR) framework took effect on June 1, 2021. Under PBR, the Companies may request to recover capital and O&M costs for approved self-build projects via the Exceptional Project Recovery Mechanism (EPRM)
- The cost methodology from the Companies is reasonable in design but, in practice, exhibits a lack of clarity without clear invoicing, itemization, or summary of costs.

Recommendations

- To enhance the accuracy of interconnection cost in the PPA price for Utility-Scale projects, the Commission could consider two different options. First, the Commission could explore the possibility of allowing the incorporation of interconnection costs in PPA prices into procurement negotiations following the completion of the System Impact Study and the Facilities Study. Second, the Commission could explore the possibility of either separating the interconnection process from the RFP process or allowing developers to have the opportunity to amend and renegotiate PPAs to reflect the trued-up interconnection costs thereby allowing PPAs to reflect the actual interconnection costs.
- The Companies should develop comparable interconnection cost metrics for self-build and IPP-built projects so that interconnection costs can be directly compared. The Companies should track the total interconnection cost of the self-build projects separately by IRS, COIF and SOIF costs so that appropriate components can be compared with the IPP-built projects.

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[111] D&O No. 21002 modified General Order No. 7, Section 2.3.G, requiring that proposed capital expenditures for any single project in excess of $2.5 million or 10 percent of the total plant in service, whichever is less, shall be submitted to the Commission for review.

7.4 Interconnection Process Reporting, Communication, and Recordkeeping

Findings

Interconnection Process Reporting to Developers

- The Companies rely on time-stamped notices, such as email communications, to maintain records of the different milestones for the interconnection process; they do not maintain a database to store this information. They also maintain a workbook to memorialize the different milestones for each active project that has not yet reached COD.
- Developers reported mixed experiences with the Companies' communication efforts with some reporting a generally positive experience and others reporting of inconsistencies when moving to different divisions of the Companies. These experiences vary by island and interconnection team.

Interconnection Process Reporting to Commission

- The Companies are required to file a monthly status report of all active IPP projects to the Commission.[112] This report contains redlined status updates to highlight any progress or issues that may have been identified for each active project.
- The Companies would benefit from investigating into file-sharing and access hosting portals, which may incorporate use of SAP, repositories, and computer-based tracking mechanisms to store and recall information that is necessary throughout the interconnection process.
- The Commission monitors the interconnection process through docketed proceedings, as well as through multiple entities hired to provide oversight on the RFP and interconnection processes. The docketed proceedings through which the Commission monitors the interconnection process include RFP Dockets (e.g., Docket No. 2017-0352[113] for Stages 1, 2, and 3 RFPs and Docket No. 2015-0389[114] for CBRE RFPs), Interconnection Docket (Docket No. 2021-0024),[115] PPA Dockets, PBR Docket (2018-0088).[116]

Recommendations

- The Companies could develop a concise centralized location for bidders to understand the interconnection process. This could include various information including interconnection requirements, bid evaluation methods, and dispute resolution process, and status on projects that are undergoing the interconnection process. It can also include a dashboard and/or interconnection capacity analysis tools for public viewing and planning. The centralized hub could also have a live interconnection portal for transparency and ease of access.
- To enhance the monitoring of the interconnection process, the Commission could explore the possibility of establishing a simplified centralized hub hosted within the Companies' or the Commission's IT system to consolidate and share interconnection reporting materials received from the Companies. Currently, the Commission monitors the interconnection process through various docketed proceedings, monthly reporting, and via the RFP process.

7.5 Dispute Resolution Process and Mediation Enhancements

Findings

- Currently, there is a formal dispute resolution process that is available to all bidders in the Utility-Scale and CBRE projects. This process is outlined in Section 1.10 of the Stage 3 RFP and in Section 1.10 of the CBRE Phase 2 RFP and pertains to any dispute for which the developer is seeking resolution.

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[112] For example, see Exhibit 1, October 2023 Report, Docket No. 2021-0024, Filed October 26, 2023.

[113] *To Institute a Proceeding Relating to a Competitive Bidding Process to Acquire Dispatchable and Renewable Generation,* Docket No. 2017-0352 (Oct. 6, 2017)

[114] *Application for Approval to Establish a Rule to Implement a Community-Based Renewable Energy Program, and Other Related Matters*, Docket. No 2015-0389 (Oct. 1, 2015)

[115] *Opening a Proceeding to Review Hawaiian Electric's Interconnection Process and Transition Plans for Retirement of Fossil Fuel Power Plants,* Docket. No 2021-0024 (Feb. 11, 2021)

[116] *Institute a Proceeding to Investigate Performance-Based Regulations,* Docket No. 2018-0088 (Apr. 18, 2018)

- Following the recommendation from Act 201 Phase 1 report, the Commission directed the IE to establish an interconnection-related dispute resolution process to address any potential disputes between the Companies and project developers. As a result, the IE helped the Commission in establishing the interconnection dispute resolution process (IDRP). The IDRP process is currently applicable for renewable projects in the Stage 3 RFP process.
- At the time of interview, three of the four utility-scale developers that participated in the Act 201 survey did not know about the IDRP framework that is currently established.
- Currently, there is no Interconnection-related dispute resolution process established to mediate disputes that may arise in CBRE projects.

Recommendations

- The Companies should share the established IDRP with developers by communicating directly with the bidders of Stage 3 RFP process. For any future RFP process, the Commission should ensure that The Companies include the established IDRP process in the RFP document. The Commission should also consider continuing the use of the IDRP framework for the future RFP projects beyond Stage 3.
- The Commission should consider developing an IDRP framework for CBRE projects similar to that which was recently developed for RFP Stage 3.
- The Commission should also take steps to raise awareness about the IE and its role to improve the outcomes of the technical aspects of the RFP and interconnection processes.

7.6 Reliability Standards and HERA

Findings

State of Hawaii Electricity Reliability Standards

- The development of reliability standards in the state have been a topic of discussion for over a decade. The Commission discussed the development of reliability standards in Docket No. 2011-0206 and a working group developed and proposed the implementation of 10 reliability standards following NERC's standard format. The Companies have reported reliability metrics that reflect some of the standards found in the RSWG report and have established interconnection standards and requirements that reflect other standards found in the RSWG report which have been incorporated into PPAs, RFP procedures, and other tariffs governing interconnection. Other standards from the RSWG report are provided through reported metrics in various dockets. The reliability-related metrics and interconnection-related requirements have been addressed in the relevant reports and initiatives. Also, new standards are being developed and introduced as industry standards are inherently an evolving process.
- In 2022, the State legislature passed legislation, enacted by former Governor Ige as Act 201, mandating the Commission conduct a study of the State's interconnection processes, evaluate the accessibility of Hawaii's electric utility grid, and identify the timeliness and costs of interconnection. In addition, Act 201 also mandated to assess reliability standards to be established by the Commission and status of HERA establishment.
- The Commission monitors several reliability metrics related to the utility's system performance and approves all interconnection requirements and procedures utilized by the utility in its RFP and interconnection processes.[117] The Commission requires the Companies to file Adequacy of Supply Reports[118] which are used to monitor the ability of the utilities to reliably serve their service territories. These reports are filed annually and detail the Companies' plan to meet their reliability planning criteria, accounting for existing resources, procurement of new resources, and retirement of aging fossil fuel resources to meet the State's RPS goals. Additionally, the Companies file monthly reports on system

[117] The Commission review reliability metrics submitted by Hawaiian Electric in multiple reports, including key performance and scorecards published on Hawaiian Electric's website and reports filed with the Commission in docketed and non-docketed proceedings. Commission approval is required for updates to tariffs and rules that contain interconnection requirements and for procurements, which contain additional requirements and procedures for the interconnection process.
[118] The annual Adequacy of Supply reports are available at: https://puc.hawaii.gov/reports/energy-reports/adequacy-of-supply/.

frequency control performance, significant system events, and curtailment of non-dispatchable renewable resources.[119]

- In 2021, the Commission established multiple trackers and incentives for the utility's performance related to reliability and power supply under the PBR framework.[120] In 2022, the Commission updated the PBR Framework to incentivize timely interconnection studies, because both the utility and developers have historically caused of delays in this area, and established a Generation Reliability PIM based on SAIDI and SAIFI metrics for generation-related service interruptions.[121] The Commission intends to continue to use the PBR framework to address concerns over interconnection costs in conjunction with policy changes being evaluated related to interconnection costs in the RFP dockets.

Hawaii Electricity Reliability Administrator (HERA)

- The Hawaii Legislature established statutes related to the Hawaii Electric Reliability Administrator (HERA),[122] which authorizes the Commission to perform different oversight functions related to electric reliability.
- In March 2022, the Commission issued an RFI soliciting capabilities and expertise of prospective entities interested in contracting with the Commission to serve as the HERA.[123] Given the Companies' Stage 3 RFP process is anticipated to begin in 2022 Q4 and given the complexity and length of time it would take to establish the HERA, the Commission has prioritized the highest impact functions of the HERA related to interconnection, and contracted with an IE in alignment with the Stage 3 RFP process to review and assist in any interconnection related issues during Stage 3 RFP process.
- As of October 2023, the Commission has hired entities to serve in the IE role to assist in both the Stage 3 RFP process and CBRE Phase 1 and 2 process. The Study Team found, based on the stakeholder interviews, that 3 of the 4 utility-scale developers in the Stage 3 RFP were not aware of the Independent Engineer or its role in the RFP and interconnection process.

Recommendations

- The Commission should develop a more systematic approach to enforcing reliability standards by revisiting the work completed by the RSWG, via Docket Number 2011-0206, and assess how the reliability standards are currently being implemented or reported, and whether some of the standards originally developed ten years ago should be replaced with new and current standards. The Commission should re-evaluate and propose updated reliability standards based on findings from subsequent proceedings, such as the IGP process. The Commission should also continue to explore cost-effective ways to implement the additional aspects of the HERA scope, including updating and enforcing reliability standards and overseeing system operations.
- The Commission should take steps to raise awareness of the Independent Engineer and its role in the RFP and interconnection process to improve outcomes related to the technical aspects of these processes.

[119] Hawaiian Electric files monthly reports in Docket No. 2011-0206, as well as on Hawaiian Electric's website, available at: https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/renewable-energy/rswg-monthly-reports.
[120] See Decision & Order No. 37787, filed in Docket No. 2018-0088 on May 17, 2021, wherein the Commission approved a suite of performance incentive mechanisms and a portfolio of scorecards and reported metrics to incentivize, track, and measure utility performance.
[121] See Decision & Order No. 38429, filed in Docket No. 2018-0088 on June 17, 2023, wherein the Commission established a suite of additional performance incentive mechanisms, including a mechanism related to interconnection study timeliness.
[122] Hawaii Revised Statutes (HRS), §269-141 through §269-149. Originally passed in 2012 as Act 166, Session Laws of Hawaii 2012.
[123] Request for Information, Hawaii Electricity Reliability Administrator, February 2022.

Appendix

A.1 Interconnection-Related Dispute Resolution Process

Table A-1: Overview of Interconnection-Related Dispute Resolution Process

Interconnection-Related Dispute Resolution Process

30 Days	***Level 1**: Bilateral Negotiation between the Two Parties in Dispute*
	The timeline for a dispute to be mediated within **Level 1** is **thirty (30) business days** from the IE's acknowledgement of receipt of a dispute. The IE may allow deadline extensions during **Level 1**. Alternatively, the IE, on case-by-case basis, may truncate the dispute resolution timeline to **less than thirty (30) business days** to meet a certain regulatory or RFP deadline. The party seeking a dispute resolution timeline **shorter than thirty (30) days** must submit this request with clear reasoning during the dispute submission process. If granted, the IE shall notify Parties of the reduced dispute resolution timeline with its acknowledgment of the dispute. The default, 30-day timeline, shall apply to a **Level 1** dispute if a request for a shorter IDRP timeline is denied.
Up to 45 Days	***Level 2**: Dispute Resolution via Mediation*
	The timeline for formal mediation will be up to **forty-five (45) business days**, depending on the number of information requests and meetings required. **Level 2** will formally commence on the date that the IE certifies that a resolution was not reached in **Level 1**. The IE will certify this based on either: (1) both parties request to proceed to mediation; or (2) the **Level 1** period for bilateral negotiations has elapsed without resolution and both parties have requested to proceed to **Level 2**. The IE will submit this certification to the PUC which will initiate the **Level 2** process. The IE will serve as the default mediator for all IDRP **Level 2** steps. The IDRP **Level 2** process proceeds only if both parties agree to the IE serving as the mediator.
PUC decision	***Level 3**: Arbitration by the PUC*
	If a resolution is not reached in **Level 2**, it shall be escalated to the PUC for the purpose of arbitration.

Table A-2: Interconnection-Related Dispute Resolution Process Level 1

IDRP Level 1

Bilateral Negotiations between the Two Parties in Dispute

5 Business Days

Step 1: Process to Submit a Dispute

Parties who challenge or contest any aspect of the interconnection process pertaining to proposed projects can submit a dispute in writing via email on company letterhead to the IE and IO and copying the Companies' appropriate RFP contact email address. The letter should clearly describe the dispute, include a chronology of events related to the dispute, and the ideal remedy, and if applicable, any alternative remedy sought.

Step 2: IE Evaluation

30 Business Days

The IE shall acknowledge the receipt of a dispute. The IE will then evaluate the party's dispute to confirm whether it is compliant with the eligible dispute requirements laid out in this framework. These actions will be completed by the IE within **five (5) business days**. The **thirty (30) day** timeline of the **IDRP Level 1 dispute resolution** starts from the date of IE acknowledgement of the dispute and confirmation of eligibility of the dispute.

Step 3: Request Information

Within **five (5) business days** of acknowledging the receipt of the dispute, the IE will transmit a request, via email, to both parties to request information from each, and to request that each propose their respective ideal resolution, and if applicable, any alternative remedy, for the dispute. Each party's proposed solution will include payment responsibilities for the various cost and schedule delays resulting from the dispute, if applicable, as well as a revised project schedule. Both parties shall respond to the information request within **ten (10) business days**.

Step 4: Facilitate Virtual Meetings with Two Petitioning Parties

The IE may facilitate discussions between the two parties, both separate calls with each party and together with both participating in the meeting. The IE will share an agenda for such meeting with the parties in advance.

Step 5: Dispute Resolution Confirmation OR *Level 2 Escalation*

The parties in dispute shall inform the IE, via email, if the raised dispute is resolved through the IDRP Level 1 process and shall provide the details of the agreed resolution. If a resolution fails to be achieved in Level 1 of the dispute resolution framework after **thirty (30) business days**

Recording and Reporting: To clarify the record of responses, the IE will maintain a summary of communications between the two parties that are related to the dispute for the duration of the Level 1 timeline. The IE will share the summary of communication to the PUC **within ten (10) business days** of dispute resolution confirmation or escalation to Level 2 via Step 1.5. The summary of communication will also be available to the petitioning parties and IO upon request.

Table A-3: Interconnection-Related Dispute Resolution Process Level 2

IDRP Level 2

Dispute Resolution via Mediation

The timeline for formal mediation will be up to **forty-five (45) business days**, depending on the number of information requests and meetings required. **Level 2** will formally commence on the date that the IE certifies that a resolution was not reached in **Level 1**. The IE will certify this based on either: (1) both parties request to proceed to mediation (Step 1.5); or (2) the Level 1 period for bilateral negotiations has elapsed without resolution and both parties have requested to proceed to **Level 2**. The IE will submit this certification to the PUC which will initiate the Level 2 process, detailed below.

Optional: Mediator Selection

5 Business Days

An alternative mediator can be selected in accordance with the Mediation Rules, Procedures, and Protocols of Dispute Prevention Resolution, Inc. ("DPR") (or its successor) or, in its absence, the American Arbitration Association. Otherwise, the IE will serve as Mediator.

Step 1: Communication From the Mediator

If there are no objections to the IE serving as Mediator, the IE shall send communication to the parties in dispute for an initial meeting within **five (5) business days** of the start of the **Level 2** dispute resolution process.

10 Business Days

Step 2: Initial Meeting

The Initial Meeting shall occur within **ten (10) business days** from the initial communication date from the Mediator. The initial meeting, facilitated by the Mediator, will include discussion of the formal mediation process including, but not limited to, the summary of the **Level 1** dispute resolution process, discussion of roles and responsibilities of all parties, and timeline. All parameters of the formal mediation process will be agreed upon in advance by all parties, including the IE, Companies, and developers.

30 Business Days

Step 3: Request Information

If deemed necessary, the Mediator shall submit multiple rounds of information requests to the involved parties. In addition, the Mediator may also request the PUC and IO to submit information requests.

Step 4: Respond to the Request

If deemed necessary, the Mediator shall submit multiple rounds of information requests to the involved parties. In addition, the Mediator may also request the PUC and IO to submit information requests.

Step 5: Additional Meetings and Information Requests

If deemed necessary, the Mediator shall request additional meetings and information with the petitioning parties. The Mediator, shall facilitate discussions, both separately with each party and together with both parties. In these meetings, the Mediator may propose solutions for the dispute in question and provide context for each party to consider in their deliberations.

Step 6: Information Review and Dispute Resolution Meeting

If deemed necessary, the Mediator shall request additional meetings with the petitioning parties. The Mediator, if deemed necessary, shall facilitate discussions, both separate calls with each party and together with both participating during the discussion. In these meetings, the mediator may propose solutions for the dispute in question and provide context for each party to consider in their deliberations.

10 Business Days

Step 7: Dispute Resolution Notice — OR — *Level 3 Escalation*

The parties in dispute shall inform the IE, via email, if the dispute has been resolved via the **Level 2** process. Should mediation prove to be unsuccessful in **Level 2**, the Mediator will make a recommendation for arbitration and/or resolution by the PUC (**Level 3**). The IE shall also prepare and submit a brief report summarizing the dispute resolution process in Level 2 to the PUC within **ten (10) business days** of either the exhaustion of the **Level 2** timeline, or after receiving notice by the parties that the dispute has been resolved.

Note: The Mediator shall keep the summary of meeting notes, which it will share with the petitioning parties, the PUC, and IO within the **five (5) business days** of the meeting date.

Table A-3: Interconnection-Related Dispute Resolution Process Level 3

IDRP Level 3

Arbitration by the PUC

10 Business Days

Step 1: Inform

The IE has **ten (10) business days** to inform the PUC of the failure of both parties to reach a resolution in **Level 2.**

10 Business Days

Step 2: Record Sharing & Recomendation

The IE will turn over all documentation collected for the dispute, including all communication logs between parties, notes from all discussions, as well as any other applicable materials. The IE will also provide a recommended outcome, in writing, to the PUC based on engineering judgment and review of the record. The documentation and recommendation will be provided to the PUC within **ten (10) business days**.

Step 3: PUC Review

The PUC Chair will designate a "Resolutions Officer" to serve as arbiter, who will review the documentation and recommendation, with aid from PUC Staff, as needed.

Step 4: PUC Resolution

Upon deliberation, the PUC Resolutions Officer will issue a resolution to the dispute by Decision & Order. The process of PUC arbitration will take no longer than **thirty (30) days** upon designation of a Resolutions Officer, and there shall be no further appeals process through the IDRP at the conclusion of **Level 3**.

A.2 Survey Question List

Interconnection Requirements

1. Which information sources did you review to understand HECO's interconnection requirements?
2. From your perspective, are interconnection requirements clearly laid out in these information sources? If not, please discuss what specific areas of these information sources could be expanded?

IRS Process

IRS Timeline

3. What is your view on overall timeline/steps for HECO's IRS process? Is there sufficient time for developers to prepare and submit technical requirements laid out in HECO's IRS process? In other words, are timeframes reasonable under each of the interconnection process phases? Please elaborate.
4. From your perspective, what are key issues impacting the IRS timeline and follow-up interconnection process? In other words, which step in the interconnection process can lead to delays regarding responsibilities of the applicant and why?
5. From your project/s IRS experience, are there any milestones that often experience delays? If yes, can you elaborate on these milestones and discuss what may have caused delays.

IRS Status/Experience of Projects

6. If the project is in **IRS process or under construction**, can you respond to the following questions?
    a. What is the status of your interconnecting project? Describe where your interconnecting project is in terms of HECO's defined IRS process.
    b. If IRS process is completed, what were the respective durations of the system impact study (SIS) and facilities study (FS) phases?
7. If the project is **under operation**, can you respond to the following questions?
    a. What were the respective durations of the system impact study (SIS) and facilities study (FS) phases?
    b. What was the duration of completing IRS process, i.e., from submitting information requested to completing the study?

Interconnection Cost and Utility Accounting

IRS related fees

8. What is your understanding of HECO's process for charging IRS related fees?

Interconnection Cost Estimates

9. Did the Companies provide a cost estimate for the interconnection costs, SIS, and FS that would be billable (with true-ups) to the customer? Do you feel the cost estimates were clearly and satisfactorily broken down?
10. What types of upgrades were triggered by the interconnecting project, if any, and what were the total attributable costs?
11. How are the Companies accounting for your responsible expenditures related to system upgrades? Describe your experience.
12. Based on your experience, were there any system upgrades that you were unfamiliar with?
13. From the perspective of the interviewee, were certain mitigations or upgrades assigned to the applicant that may have been otherwise funded through other sources, lower-cost opportunities, or system planning functions? (i.e., standard grid enhancements planned by the Companies)
    a. If so, did you contest any costs? And what was the outcome, if the case?
14. During the IRS process of the project, has your team experienced unexpected or unexplained costs associated with project management fees? If so, explain the situation and unexpected costs.

Actual Cost & True-Ups

15. Please describe the true-up process for additionally incurred fees.
    a. Are invoices itemized with the upgrades and mitigations?
16. Have any of the cost estimates changed within a significant deviation (say more than twenty-five precent deviation) from the interconnection cost estimates forecasted by the Companies? If so, how much and in which direction?

Invoicing and Payment

17. Prior to the SIS and FS phases, what was the first payment paid to HECO (for each project)?
18. What and how much were the second payments that were incurred to complete the IRS Amendment?
19. Were the SIS and FS costs presented clearly and in detail in any formal estimate?
20. Was a summary of findings and additional costs communicated to the interviewee (for each project)?

Interconnection Delays

21. Have your project/s faced any interconnection-related delays?
22. If yes, what are the most common reasons for missed timeline milestones (delays in outlined steps) by the Companies? In other words, from the initial bid submission to receiving COD assignment, which stage(s) resulted in the most delays from the IRS and other interconnection related process?
23. Has a lack of payment (from the applicant) or delay in invoicing (from the Companies) led to a delay in the interconnection process?
24. Have any other factors (e.g., permitting, siting, environmental studies, etc.) delayed the timeline of your project?

Technical Analysis/Requirements

25. Were requests for information made by the Companies appropriate in order to facilitate the SIS and FS phase?
26. Were technical results summaries understandable and clearly communicated to the interviewee?
27. Are there any common challenges faced during the SIS an FS process and do the Companies take action to reconcile them?
28. Do you have an opinion of whether the revealed upgrades due to the interconnecting project were fair and justified?
29. Did any issue on your project trigger a re-study or additional studies? If so, could you please describe those circumstances. Did these studies lead to a delay in the interconnection process, and if so, how long was this delay?

Customer Service and Communication

30. Was the interviewee assigned a point of contact (POC) from HECO in handling the interconnecting project?
31. Please describe the modes and methods in which you would provide and receive information throughout the interconnection process.
32. Were there any concerns that required escalation to superiors at the Companies? If so, please describe the circumstance and resolution process.
33. On average, how long were the response times from the POC and/or customer service team?
34. Please describe your overall experience working with the different divisions at the Companies respective to the various milestones and phases.

Recordkeeping and Process Reporting

35. Please describe your project's user interface experience with the online interconnection platforms.
36. To your understanding, how was information stored on the side of HECO?

37. What was your process of requesting and receiving information related to the project(s)?
38. How were milestones tracked and communicated throughout each phase of the interconnection process?
39. How was confidentiality handled by the Companies, if applicable?
40. Did you experience challenges in transferring information to another department, division, or personnel? If so, please describe the situation.
41. Did recordkeeping and process reporting practices contribute to any delays in the interconnection process? If so, please elaborate. Does the interviewee have an opinion on the recordkeeping practices of the Companies?

Dispute Resolution

42. What issues might trigger a formal dispute resolution process through the Commission's facilitation?
43. Have there been any instances where a circumstance may have warranted this higher elevation of mediation? If so, please describe the situation.
44. What are acceptable timelines in resolving varying levels of grievances through a formal dispute resolution process?
45. Do you have any additional comments regarding program enhancements to mitigate future concerns?
46. Are you aware of any interconnection-related dispute resolution process established by the Commission? If yes, please share your understanding and whether your projects have considered using the established dispute resolution process.

General

47. Please describe successes and positive experiences with interconnecting a project. What worked well and what can be applied to a program enhancement?
48. Are there areas in which the Companies can streamline interconnecting projects? Please describe.
49. Do you have any other interconnection related experience that you would like to share with us?

Independent Engineer

50. question is optional. If you are currently involved in the Stage 3 RFP, please describe your understanding of the role of the Independent Engineer. Have the Companies provided any information to you regarding the role of the Independent Engineer?

About PA.

We believe in the power of ingenuity to build a positive human future.

As strategies, technologies, and innovation collide, we create opportunity from complexity.

Our diverse teams of experts combine innovative thinking and breakthrough technologies to progress further, faster. Our clients adapt and transform, and together we achieve enduring results.

We are over 4,000 strategists, innovators, designers, consultants, digital experts, scientists, engineers, and technologists. And we have deep expertise in consumer and manufacturing, defense and security, energy and utilities, financial services, government and public services, health and life sciences, and transport.

Our teams operate globally from offices across the UK, Ireland, US, Nordics, and Netherlands.

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