Hawaiian Electric

Distribution DER Hosting Capacity Grid Needs

November 2021 Update

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1 Introduction

On August 3, 2021, the Companies submitted their updated and revised Integrated Grid Planning ("IGP") Inputs & Assumptions and Distribution DER Hosting Capacity Grid Needs documents under Docket No. 2018-0165.[1] This document is an update to the Distribution DER Hosting Capacity Grid Needs document.

The distributed energy resources ("DER") hosting capacity grid needs identified in the August 3, 2021 filing were driven by the forecasted DER growth on distribution circuits based on the market DER forecast provided in the 2020 Integrated Grid Planning Inputs and Assumptions March 2021 Update.[2] This DER hosting capacity grid needs update is being filed to reflect the updated DER forecast sensitivities provided in the Hawaiian Electric Revision to Updated and Revised Inputs and Assumptions ("August Update") filed on August 19, 2021.[3] The update provides low, base, and high DER forecast sensitivities to identify hosting capacity grid needs for the next five years. These three sensitivities correspond to low, base, and high scenarios to provide a bookend approach around a reference, or base, forecast. Note that the base (or reference) scenario[4] has also been updated since the August 3 filing. A preliminary report using the high DER forecast, the October 2021 Update, [5] was provided to the Stakeholder Technical Working Group ("STWG") for review and to provide feedback. A summary of the feedback is provided in Appendix B:.[6]

The DER hosting capacity grid needs analysis is part of the Distribution Planning Process employed by the Company to plan the future of the distribution system. The Distribution Planning Process as described in the *Distribution Planning Methodology*[7,8] was developed in

[1] *See* Hawaiian Electric Updated and Revised Inputs and Assumptions & Distribution DER Hosting Capacity Grid Needs filed on August 3, 2021 in Docket No. 2018-0165, Instituting a Proceeding to Investigate Integrated Grid Planning.

[2] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20210330_wg_fa_deliverable_draft.pdf

[3] *See* Hawaiian Electric Revision to Updated and Revised Inputs and Assumptions filed on August 19, 2021 in Docket No 2018-0165.

[4] The August 3, 2021 filing was based on the market DER forecast provided in the 2020 Integrated Grid Planning Inputs and Assumptions March 2021 Update. Since then, the IGP DER forecasts were updated and filed on August 3, 2021. The low, base, and high scenarios in this analysis utilize the August 3 updates.

[5] *See* https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/key-stakeholder-documents

The analysis presented herein was revised as needed and results may differ from the October 2021 Update provided on October 1, 2021.

[7] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/distribution_planning/20200602_dpwg_distribution_planning_methodology.pdf

[8] Concurrent to this filing, an update to the Distribution Planning Methodology was filed in the Grid Needs Assessment (Nov. 2021, Dkt. No. 2018-0165). References in this document are made to the document in footnote 8.

collaboration with stakeholder and customer engagement through the Distribution Planning Working Group ("DPWG"). The document was developed to identify the steps and tools used by the Company to analyze the distribution system and determine grid needs required to serve load growth and safely interconnect DER while maintaining power quality and reliability for all customers.

The Process is comprised of four stages: forecast, analysis, solution options, and evaluation.

1. **Forecast Stage**: Develop circuit-level forecasts based on the corporate demand forecast.
2. **Analysis Stage**: Determine the adequacy of the distribution system.
3. **Solution Options Stage**: Identify the grid needs requirements.
4. **Evaluation Stage**: Evaluation of solutions.

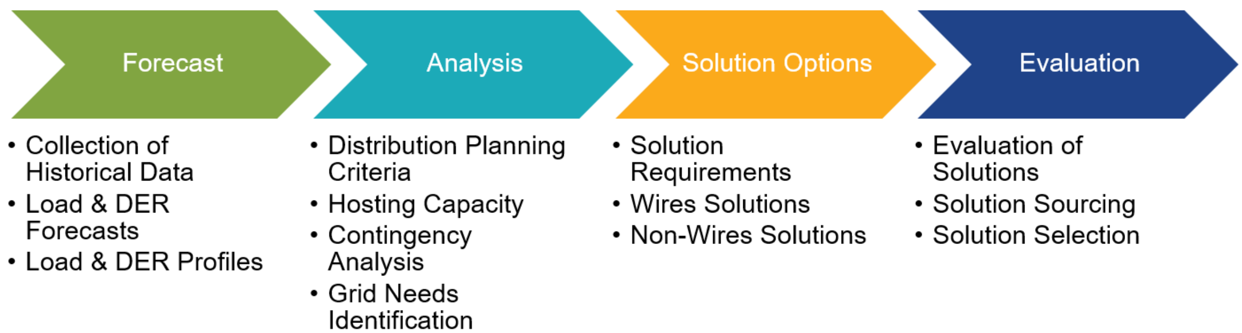

Figure 1: Stages of the Distribution Planning Process

This Distribution Planning Process is incorporated into the IGP process as it uses the corporate forecasts that include planned electrical demand and DER developed through IGP as an input to the distribution planning analyses to identify distribution grid needs. These distribution grid needs are then used as an input into the IGP process which will select portfolios of solutions to address resource, transmission, and distribution needs. The figure below shows how the Distribution Planning Process (see orange box) is performed in parallel which then converges with other identified steps in the IGP Process.

Figure 2: Distribution Planning Process and IGP Process[9]

This document focuses on hosting capacity grid needs identified for the next five years (year 2021 through 2025) driven by the forecasted DER growth on distribution circuits based on forecast sensitivities provided in the August Update.

As discussed in the August Update, various forecast sensitivities and scenarios were developed to address forecasting uncertainty. Three scenarios were selected from the August Update to provide a bookend approach to demonstrate the range of possible DER adoption and are summarized in the following table.[10]

[9] Hawaiian Electric, Presentation to IGP Stakeholder Technical Working Group, June 17, 2021.

[10] *See* Hawaiian Electric Revision to Updated and Revised Inputs and Assumptions filed on August 19, 2021 in Docket No 2018-0165. Table 6-3.

Table 1-1. DER Scenarios from August 2021 Update

No.	*Modeling Case*	*DER Forecast*
1	*Base*	*Base Forecast*
2	*High Load Customer Technology Adoption Bookend*	*Low Forecast*
3	*Low Load Customer Technology Adoption Bookend*	*High Forecast*

Hosting Capacity Grid Needs

The overall process and methodology, using modeling tools such as LoadSEER and Synergi,[11] to develop the grid needs driven by hosting capacity is provided herein. Since this report addresses the hosting capacity grid needs specifically, the distribution planning process figure discussed at the recent Stakeholder Technical Working Group meeting in June 2021[12] was streamlined to show details related only to this analysis and is shown in Figure 3. Potential wires and non-wires alternative ("NWA") solutions opportunities using the Non-Wires Opportunity Evaluation Methodology Report[13] will be evaluated later as part of the IGP process.

[11] *See* Hawaiian Electric, *Distribution Planning Methodology*, June 2020 for an overview of the LoadSEER and Synergi models.

[12] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/20210617_presentation_slides_igp_stakeholder.pdf at slide 20.

[13] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/distribution_planning/20200602_dpwg_non_wires_opportunity_evaluation_methodology.pdf

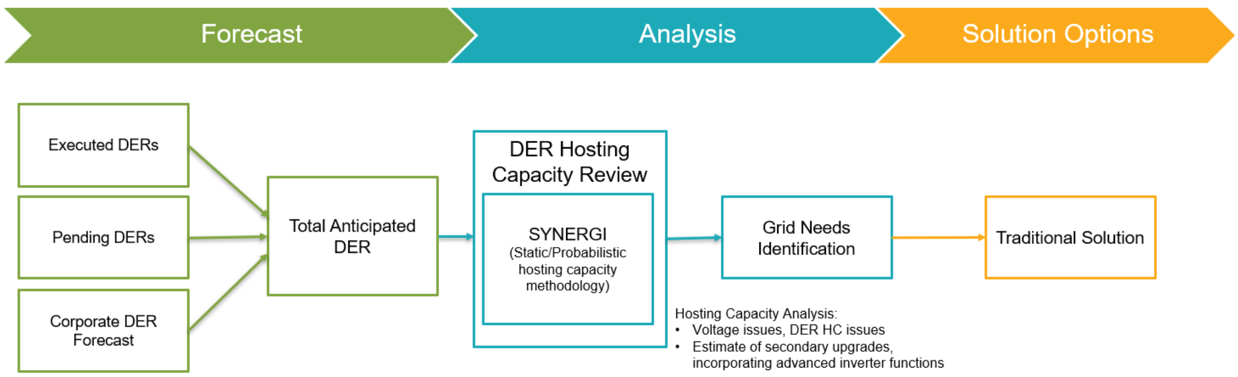

Figure 3: Hosting Capacity Grid Needs Identification Stages

The distribution planning criteria is used to establish circuit-level hosting capacity which is a circuit's ability to accommodate or host DERs to an identified kilowatt (kW) amount based on steady state load flow analyses. The methodology used to develop these hosting capacity numbers is geared towards analyzing DER growth due to small systems distributed on a circuit. Single large DER interconnections are typically evaluated on a case-by-case basis because their impact on the circuit largely depends on its generating capacity and location. In other words, circuit-level hosting capacity is the maximum aggregate kW amount of small scale DERs a circuit can host before any thermal or voltage violations occur.[14] This hosting capacity kW is utilized to identify the circuits with a grid need when the forecasted DER reaches this identified amount.

The following steps are used to identify circuits with hosting capacity violations in the next five years based on the current market DER forecast:

1. Determine the annual anticipated DER (kW) by circuit.
2. Screen circuits for analysis.
3. Perform substation transformer and circuit-level hosting capacity analysis.
4. Identify grid needs and solution options.

Throughout the year, Hawaiian Electric reviews and processes DER applications. In accordance with the Initial Technical Review ("ITR") process outlined in Rule 14H, the hosting capacity screen is one step in the overall interconnection technical review and addresses several screens outlined in Rule 14H.

[14] Hawaiian Electric, *Distribution Planning Methodology* June 2020, at 12.

2 Total Anticipated DER By Circuit

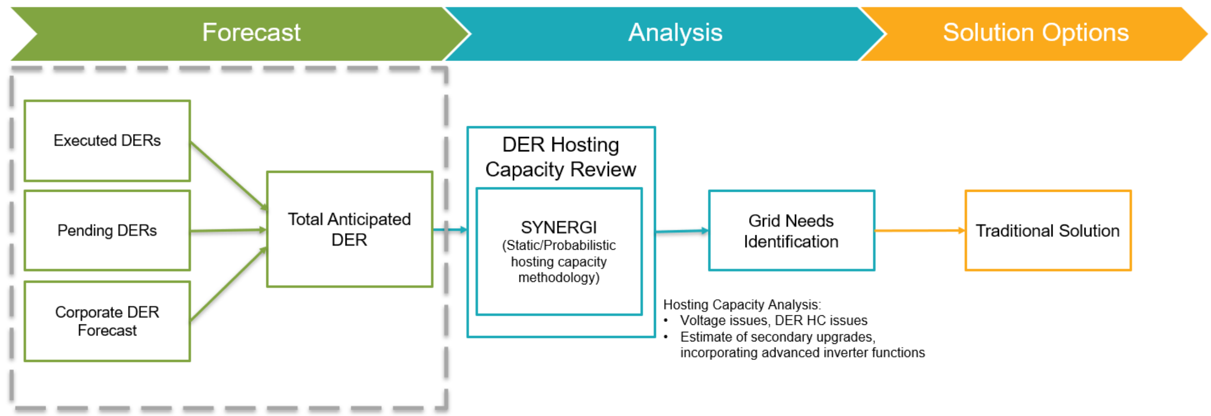

Figure 4: Forecast Stage of the Distribution Planning Process

This section describes the first step used to identify hosting capacity driven distribution grid needs:

1. **Determine the total anticipated DER (kW) by circuit.**
2. Screen circuits for analysis.
3. Perform substation transformer and circuit-level hosting capacity analysis.
4. Identify grid needs and solution options.

The total anticipated DER for a circuit is calculated by adding together the aggregate executed DER on that circuit and the forecasted DER growth for that circuit. The two components of this calculation are explained in the following sections.

$$Total\ Anticipated\ DER = Aggregated\ Executed\ DER + Adjusted\ DER\ Growth$$

The steps described in this section to determine the total anticipated DER by circuit were repeated for each of the DER forecasts: base, low, and high forecast.

2.1 AGGREGATE EXECUTED DER

The first step is to identify the existing DER on the circuits. Executed DER at the beginning of the study period is aggregated by total program size (kW) by circuit.[15] The programs included are:

- Net Energy Metering ("NEM")
- Feed-In Tariff ("FIT")
- Customer Grid Supply ("CGS")
- Customer Self-Supply ("CSS")
- Customer Grid Supply Plus ("GSP")
- Smart Export ("ISE")
- Net Energy Metering Plus ("NEM Plus" or "NMP")
- Standard Interconnection Agreement ("SIA")
- Community-Based Renewable Energy ("CBRE") Phase 1
- Power Purchase Agreement ("PPA")

For purposes of this hosting capacity analysis, battery energy storage capacity is not included in the aggregated DER values as it is assumed that energy storage systems will not export during the day.

2.2 ADJUSTED DER GROWTH BY CIRCUIT

The corporate demand forecast is provided at the system level, meaning there is one forecast for each island, and is built with separate layers such as underlying load, DER, energy efficiency ("EE"), and electric vehicles ("EV"). To perform the distribution planning hosting capacity analyses that typically occur at the circuit-level, the forecasted DER growth by feeder is determined based on the corporate DER forecast. Adjustments to the forecasted DER growth are made to account for any DER not captured, such as CBRE Phase 2 small projects, and explained in the following sections. The adjusted DER growth is then added to the aggregated executed DER to get the total anticipated DER by circuit used during the hosting capacity assessment in the Analysis stage.

The forecasted DER growth by feeder is derived from the corporate DER forecasts[16] using LoadSEER when available. Currently, LoadSEER models are available only for O'ahu with plans

[15] Executed programs as of December 31, 2020 are included.

[16] The DER forecasts (DER growth) by island are provided in Excel workbooks. See Appendix A:.

for implementation in the middle of 2022 on the islands of Maui and Hawai'i Island[17]. Since LoadSEER was recently adopted by the Company to create circuit-level forecasts, models for all islands are not fully built or complete to implement LoadSEER for this process. For all other islands, the forecasted DER growth is developed by allocating an island's corporate DER forecast proportional to the amount of executed DER on each circuit as a percentage of total executed DER on that island. In summary, the forecasted DER growth by year by circuit is determined using one of the following methods:

1. DER forecast allocation in LoadSEER.
2. DER forecast allocation based on existing DER.

Adjustments are also made to the forecasted DER growth by feeder to account for pending known large projects such as CBRE Phase 1, FIT, and large SIA (>250kW) projects. Because size and location of these projects are already known, they are added to the respective circuits in the estimated year of execution to get the adjusted DER growth by feeder. [18]

$$Forecasted\ DER\ Growth = Corporate\ DER\ Forecast + Adjustments$$ [19]

$$Adjusted\ DER\ Growth = Forecasted\ DER\ Growth + Large\ Project\ Adjustments$$ [20]

2.2.1 DER Forecast Allocation in LoadSEER

LoadSEER is an electric load forecasting software that creates circuit-level forecasts by combining historical SCADA and weather data along with forecasted new load, DER, EV, and EE spatially allocated throughout the system. LoadSEER spatially allocates these layers at the distribution level through an agent-based simulation that determines the likelihood (i.e., propensity score) that each of these types will be adopted at each service point. This process refines the system level forecast and provides location information such as customer consumption, historical DER adoption, census tract data, among others, with circuit-level forecasts. LoadSEER constrains the total amount that gets allocated for each of these layers by an incremental system level limit for each layer. The system level constraint is based on the corporate DER forecast. The resulting DER forecast allocation provides the feeder-level forecasted DER growth that is needed to calculate the adjusted DER forecast and thus the total anticipated DER by feeder.

The corporate DER forecast includes NEM, CGS, CSS, GSP, ISE, NMP, SIA, and a future program. Adjustments are made to the corporate DER forecast to account for the CBRE Phase

[17] The implementation of LoadSEER for the neighbor islands is targeted for middle of 2022 as reported in Exhibit 2 of Hawaiian Electric Companies' Quarterly DER Technical Report filed on September 30, 2021 in Docket No. 2019-0323.

[18] The DER growth by feeder (circuit) are provided in Excel workbooks. See Appendix A:.

[19] Adjustment for CBRE Phase 2 small projects.

[20] Large project adjustments include CBRE Phase 1, FIT, and large SIA (> 250 kW).

2 small projects program as well as pending CBRE Phase 1 and large (>250kW) SIA projects. For this update, the amount of CBRE Phase 2 small projects was revised to 30 MW[21] to be consistent with the 30 MW small project capacity described in the latest Order.[22] This 30MW of CBRE Phase 2 small projects were included by adding 6 MW per year to the corporate DER forecast. This was done for each scenario: Base, Low, and High. This amount is divided into residential and commercial customer types and is used as the system level DER limit for the spatial allocation in LoadSEER. LoadSEER can consider separate residential and commercial DER profiles when building feeder-level forecasts which will be important for the location-based forecasts provided in the Location-Based Forecasts for Distribution Grid Needs included with this filing. However, the residential/commercial split was not necessary for this hosting capacity grid needs analysis.

The resulting DER forecast allocation is then adjusted by adding pending CBRE Phase 1 and large SIA projects. Because the project size and location of these pending projects are already known, these adjustments were added to the individual feeder forecasted DER growth to produce the adjusted DER by feeder. The adjusted DER forecast is added to the aggregate executed DER to produce the total anticipated DER that is used in the Analysis stage.

In summary, the steps to determine the total anticipated DER by circuit by year are:

1. Starting with the corporate DER forecast, add 30 MW for CBRE Phase 2 small projects.
2. Run spatial allocation in LoadSEER to derive the forecasted DER growth by year by circuit.
3. Add pending large projects to construct adjusted DER by year by circuit.
4. Add aggregate executed DER to get the total anticipated DER.

2.2.2 DER Forecast Allocation Based on Existing DER

Since LoadSEER models are unavailable for Hawai‘i Island and Maui County, a different method for the DER forecast allocation was required. This method involves allocating a system level amount proportional to the amount of executed DER in selected programs[23] on each circuit.

Similar to O‘ahu, the corporate DER forecasts for Hawai‘i Island and Maui County need to be adjusted for CBRE Phase 2 small projects and pending CBRE Phase 1 and FIT projects to get the system level amounts to allocate. The different CBRE Phase 2 small projects program cap

[21] The August 3, 2021 filing assumed 40 MW of CBRE Phase 2 small projects.

[22] *See* Order No. 37879 issued on July 27, 2021 in Docket No. 2015-0389, Approving the March 30 CBRE Filings, with Modifications.

[23] Selected programs include NEM, CGS, CSS, GSP, ISE, NMP, and SIA.

for each island is considered in the calculation of the adjusted DER forecast. The CBRE Phase 2 small projects added are consistent with the capacities described in the latest Order.[24]

The proportional amount that determines the allocation is calculated as the executed DER in selected programs on a feeder as a percentage of the total system executed DER in those same selected programs. The executed FIT and PPA projects are removed from the aggregate executed DER for each feeder as determined above in Section 2.1 to get the amount of executed DER in the selected programs for each feeder. Including only these smaller type programs in this calculation focuses the forecasted DER growth on increasing residential DER systems. The executed FIT and PPA projects were removed because these are typically larger projects that would slant the results of this calculation toward these circuits where small DER may not be as likely to be adopted.

Next, the amount of executed DER in the selected programs on that circuit is expressed as a percentage of the total executed DER in those selected programs on the respective island. The incremental system level DER limit based on the corporate forecast and CBRE Phase 2 small projects is then allocated to the circuit based on this percentage. For example, if the executed DER in the selected programs on a circuit is 5% of the total executed DER on that island, 5% of the adjusted DER forecast will be allocated to that circuit. Pending CBRE Phase 1 and FIT projects are added to the resulting feeder-level forecasted DER growth to get the adjusted DER growth. The adjusted DER growth is added to the aggregate executed DER to produce the total anticipated DER that is used in the Analysis stage.

In summary, the steps to get the total anticipated DER by circuit by year are:

1. Starting with the corporate DER forecast, add CBRE Phase 2 small projects.

2. Determine forecasted DER growth by year by circuit.
    a. Remove the executed FIT and PPA projects from the aggregate executed DER for each feeder to get the amount of executed DER in the selected programs on each feeder.

    b. Calculate the executed DER in the selected programs on each circuit as a percentage of total executed DER in those selected programs on that island.

$$\%\ Circuit\ Allocation_{DER} = \frac{Executed\ DER\ in\ selected\ programs\ on\ Circuit}{Total\ Executed\ DER\ in\ selected\ programs}$$

[24] *See* Order No. 37879 issued on July 27, 2021 in Docket No. 2015-0389, Approving the March 30 CBRE Filings, with Modifications at 33.

c. Allocate the incremental system level DER limit for each year (year 2021 through 2025) among circuits based on the percentage calculated in the previous step.

3. Add pending large projects to construct adjusted DER by year by circuit.

$$\text{DER Forecast Allocation} = (\%\ Circuit\ Allocation_{DER}) \times (Incremental\ system\ level\ DER\ limit)$$

4. Add aggregate executed DER to get the total anticipated DER.

3 Analysis

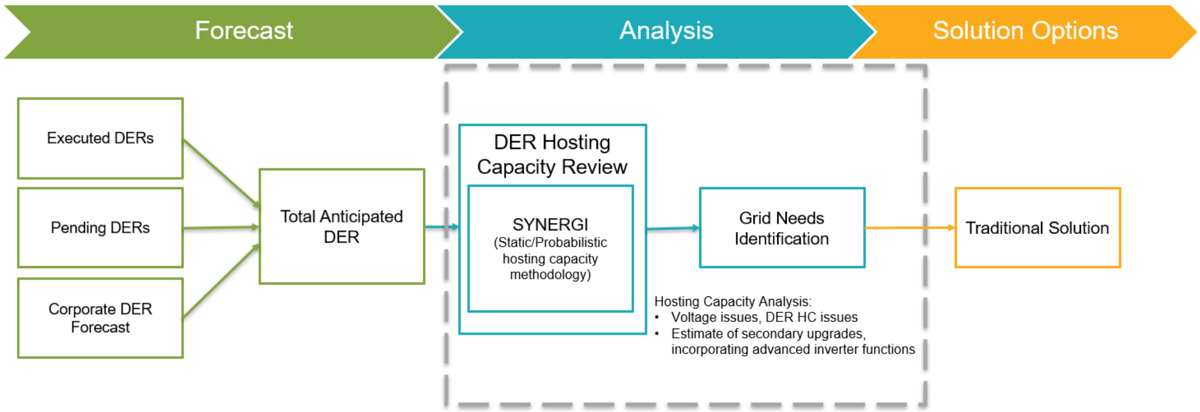

Figure 5. Analysis Stage of the Distribution Planning Process

This section describes steps 2 and 3 used to identify hosting capacity driven distribution grid needs:

1. Determine the annual anticipated DER (kW) by circuit.
2. **Screen circuits for analysis.**
3. **Perform substation transformer and circuit-level hosting capacity analysis.**
4. Identify grid needs and solution options.

The steps described in this section to determine the total anticipated DER by circuit were repeated for each of the DER forecasts: base, low, and high forecast. A circuit-level hosting capacity assessment is used to determine if a circuit can accommodate the anticipated DER in the study period. A summary of the circuit selection and hosting capacity analysis process is shown in the figure below.

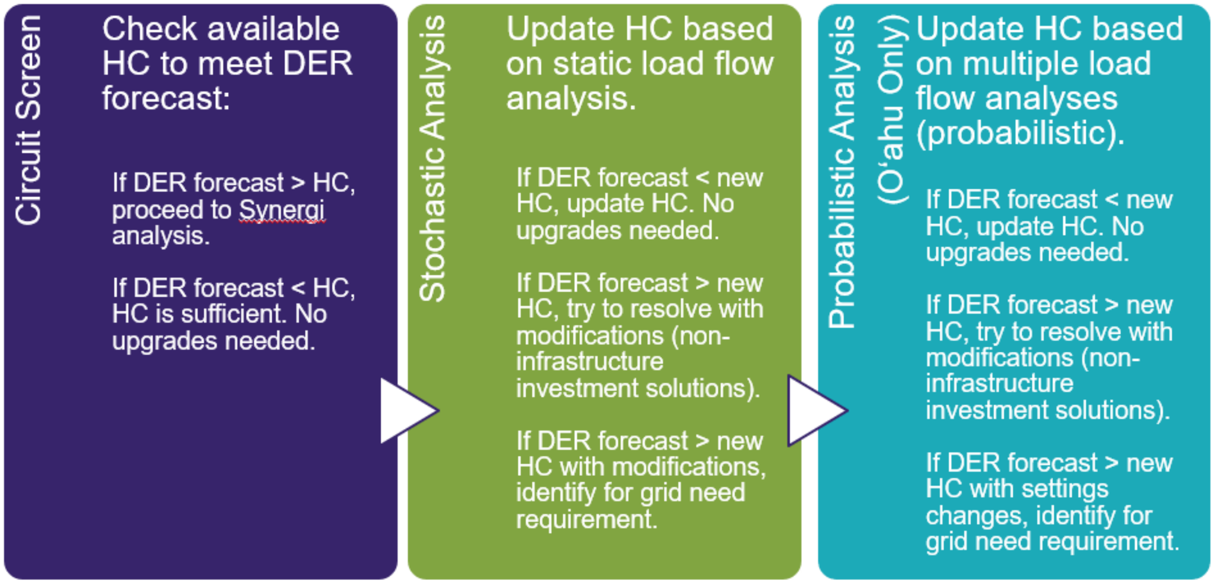

Figure 6. Summary of Hosting Capacity Analysis

3.1 SCREEN CIRCUITS FOR ANALYSIS

The Company utilizes a multi-step screening process, which increases in complexity (i.e., time and resources) to further assess the circuit's ability to host the forecasted DER. Circuits are screened and selected by comparing the anticipated DER by circuit described in Section 2 with the current hosting capacity to determine if the current circuit hosting capacity can accommodate the level of total anticipated DER in the last year of the study period (year 2025). If a circuit is unable to accommodate the anticipated DER in year 2025 with its current hosting capacity, the circuit is selected for further analysis where the hosting capacity is reassessed.

In summary, circuits are selected for further analysis if:

- Total anticipated DER in the year 2025 is greater than the current hosting capacity.

If the total anticipated DER in year 2025 is less than the current hosting capacity, then there are no grid needs and no further analysis is required.

Using this selection screening criteria, a total of 185 circuits using the high DER forecast, 111 circuits using the base DER forecast, and 103 circuits using the low DER forecast are selected for further analysis. A summary of the circuits selected by island and forecast is shown in the

table below. Company-owned radial distribution circuits are included in the hosting capacity analysis. Dedicated and network (non-radial) circuits are not included in the tables.

Table 3-1: Summary of Circuit Selection Screening

Island	Total Circuits	Existing Hosting Capacity Satisfies Need (Analysis Not Required)			Total Anticipated DER in 2025 > Hosting Capacity (Analysis Required)		
		Low	Base	High	Low	Base	High
O‘ahu	384	357	350	303	27	34	81
Hawai‘i Island	137	95	95	76	42	42	61
Maui Island	88	59	58	52	29	30	36
Lana‘i	3	1	1	1	2	2	2
Moloka‘i	8	5	5	3	3	3	5
Total (All Islands)	620	517	509	435	103	111	185

3.2 HOSTING CAPACITY ASSESSMENT

If a circuit is selected for further analysis, the circuit-level hosting capacity is reassessed and updated using one or both of the following methods:

1. Stochastic hosting capacity methodology.
2. Probabilistic hosting capacity methodology.

Both methods use the Synergi load flow software to simulate DER growth to determine the circuit hosting capacity for DER.

A stochastic hosting capacity analysis is done first. This method analyzes specific points in time that envelope the circuit's characteristics. This method is a much quicker analysis compared to the probabilistic method which is computationally intensive performing the analysis over a variation of DER growth scenarios utilizing time series data. The updated hosting capacity is then compared to the amount of anticipated DER in year 2025. If the revised hosting capacity is greater than the amount of anticipated DER in year 2025, there are no grid needs and no further analysis is required.

If the updated hosting capacity is less than the anticipated DER in year 2025, a subsequent hosting capacity evaluation may be performed using the probabilistic hosting capacity for circuits with available models. If the probabilistic hosting capacity is higher than the anticipated DER in year 2025, the probabilistic hosting capacity will become the updated hosting capacity.

If the stochastic hosting capacity or probabilistic hosting capacity result is less than the anticipated DER in year 2025, the circuit is identified as requiring solution options and further described in Section 3.5.

3.3 STOCHASTIC HOSTING CAPACITY METHODOLOGY (PV GROW)

Initially, the hosting capacity is reassessed using Synergi's built-in PV Grow function. PV Grow stochastically adds PV generators to the selected feeders in proportion to customer load. Generators are added to the feeders until an exception, such as a voltage or thermal violation, occurs. Once an exception is hit, the amount of PV (kW) added plus existing becomes the feeder hosting capacity.

In this analysis, the hosting capacity is determined for a snapshot in time, specifically, the hour representing the daytime minimum load ("DML") and does not account for the capacity available at other hours which may vary due to load variations throughout the day. To perform this analysis, the following circuit data is input into Synergi:

- Minimum gross demand (kVA and kW) and date and time of occurrence.
- Peak demand (kVA and kW) and date and time of occurrence.

A load flow is simulated in conjunction with the PV Grow analysis to assess daytime minimum load conditions and hosting capacity for the base case. If there are base case violations, such as high and low voltages or thermal overloads, or the hosting capacity is lower than the anticipated DER, then simple mitigation solutions such as modifications to existing equipment (i.e. modifications that do not require infrastructure investments) will be applied and simulated again. These modifications may include substation LTC setting changes, switching, or phase balancing. If a solution option involves substation LTC setting changes then a load flow is also simulated using the peak demand case to verify no violations will occur with the new settings. This process is repeated until a solution option is found that results in no violations in both the DML and peak cases, and hosting capacity accommodates the anticipated DER. The results from the PV Grow analysis is the updated hosting capacity.

If no solution can be found using the PV Grow analysis, then additional analysis may be performed using the probabilistic hosting capacity methodology described below or the circuit is identified as requiring a grid need. Results of the PV Grow analysis are shown in Table 2.

3.4 PROBABILISTIC HOSTING CAPACITY METHODOLOGY

The probabilistic hosting capacity is an updated methodology developed in collaboration with the Electric Power Research Institute ("EPRI") that resulted from discussions with stakeholders to improve the hosting capacity methodology.[25] In contrast to the initial hosting capacity analysis, using the Synergi PV Grow function, that models a single DER growth scenario for a single hour, this updated method models 576 hourly profiles. Probabilistic modeling techniques are applied to calculate hosting capacity under multiple DER growth scenarios to provide a more robust hosting capacity and is described in further detail in the *Distribution Planning Methodology*. [26]

The hosting capacity is determined by creating a base case of the circuit model and utilizing circuit-level forecasts generated from LoadSEER, solar irradiance profiles and the scripts developed by EPRI in Synergi to execute the probabilistic hosting capacity analysis. The analysis produces a feeder hosting capacity profile by statistically analyzing feeder exceptions found at different DER penetration levels across multiple DER growth scenarios. Therefore, these results are expected to be a more precise representation of feeder hosting capacity thresholds than results from the PV Grow analysis.

Similar to the stochastic hosting capacity analysis, the probabilistic hosting capacity results are compared to the total anticipated DER in year 2025. If the probabilistic hosting capacity is higher than the anticipated DER, the results become the updated hosting capacity. If the probabilistic hosting capacity is lower than the anticipated DER, simple non-infrastructure investment solutions may be considered and reanalyzed. If the probabilistic hosting capacity is still lower than the anticipated DER, the circuit is identified as requiring a grid need. Results of the probabilistic hosting capacity analysis for O'ahu are combined with the results from Section 3.3 and are shown in Table 2.

[25] *See* Hawaiian Electric Companies' Initial Statement of Position on Deferred Issues and Technical Track Issues issued on August 14, 2017 in Docket No. 2014-0192.

[26] Hawaiian Electric, *Distribution Planning Methodology,* June 2020 at 13-17.

3.5 HOSTING CAPACITY RESULTS

The hosting capacity analysis results are grouped into the following categories by circuit:

- **Existing Hosting Capacity Satisfies Need**: Existing hosting capacity can accommodate the total anticipated DER in year 2025. No grid needs are required.
- **Updated Hosting Capacity (Without Modifications) Satisfies Need:** Updated hosting capacity can accommodate the total anticipated DER in year 2025. No grid needs are required.
- **Updated Hosting Capacity (With Modifications) Satisfies Need:** Updated hosting capacity along with modifications that do not require infrastructure investments can accommodate the total anticipated DER in year 2025.
- **Solution Option Required:** Updated hosting capacity is unable to accommodate the total anticipated DER in year 2025. Grid need identified.

A summary of the hosting capacity assessment by island is shown below using each forecast. The results for O‘ahu include results from both the stochastic and probabilistic analyses. For all other islands, the results are from the PV Grow analysis. Hosting capacity results by circuit by island are provided in the workbooks described in Appendix A:.

Table 3-2: Summary of Hosting Capacity Results

Island	Forecast	Grid Needs Not Required		Grid Needs Required		Total Circuits
		Existing Hosting Capacity Satisfies Need	Updated HC (w/o modifications) Satisfies Need	Updated HC (w/ modifications) Satisfies Need	Solution Option Required	
O'ahu	High	303	49	15	17	384
	Base	350	22	6	6	384
	Low	357	17	5	5	384
Hawai'i Island	High	76	27	32	2	137
	Base	95	21	19	2	137
	Low	95	21	19	2	137
Maui Island	High	52	16	13	7	88
	Base	58	15	12	3	88
	Low	59	15	11	3	88
Lana'i	High	1	0	0	2	3
	Base	1	0	0	2	3
	Low	1	0	0	2	3
Moloka'i	High	3	0	0	5	8
	Base	5	0	0	3	8
	Low	5	0	0	3	8
Total (All Islands)	High	435	92	60	33	620
	Base	509	58	37	16	620
	Low	517	53	35	15	620

3.5.1 High DER Forecast

Of the 620 circuits assessed, 435 circuits are able to accommodate the total anticipated DER in 2025 with the existing hosting capacity using the high DER forecast. In addition, 92 circuits are able to accommodate the anticipated DER through an updated hosting capacity without grid needs. The remaining 93 circuits are identified as requiring grid needs and are discussed in the Section 4.

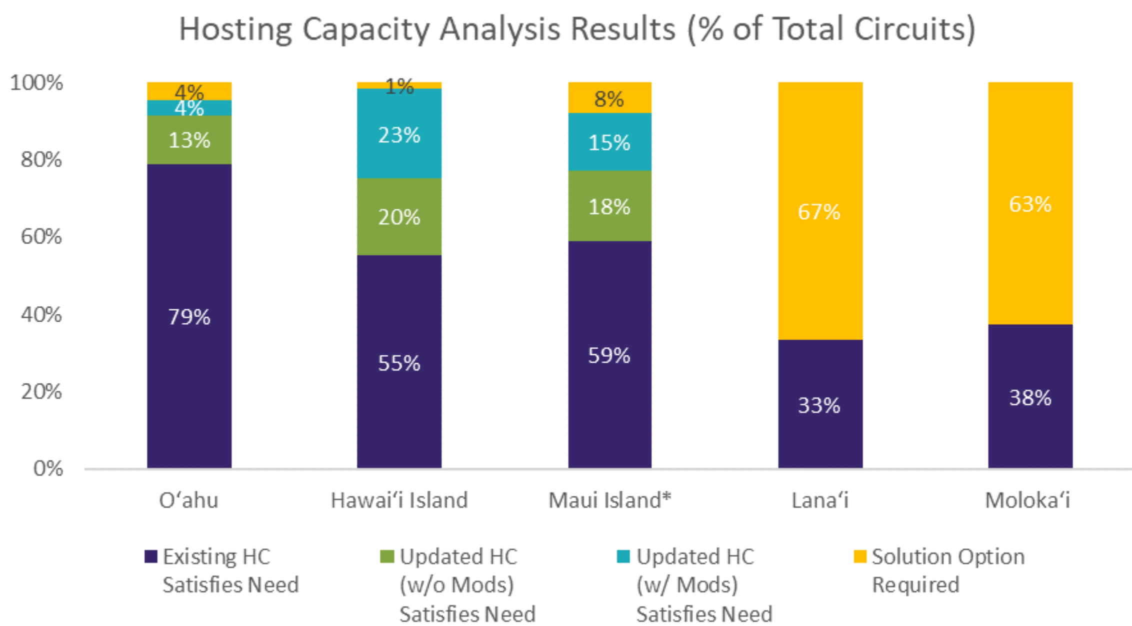

Figure 7: Summary of Hosting Capacity Results (% of Total Circuits) Using the High DER Forecast[27]

[27] Total percentage does not equal to 100 % due to rounding.

3.5.2 Base DER Forecast

Of the 620 circuits assessed, 509 circuits are able to accommodate the total anticipated DER in 2025 with the existing hosting capacity using the base DER forecast. In addition, 58 circuits are able to accommodate the anticipated DER through an updated hosting capacity without grid needs. The remaining 53 circuits are identified as requiring grid needs and are discussed in the Section 4.

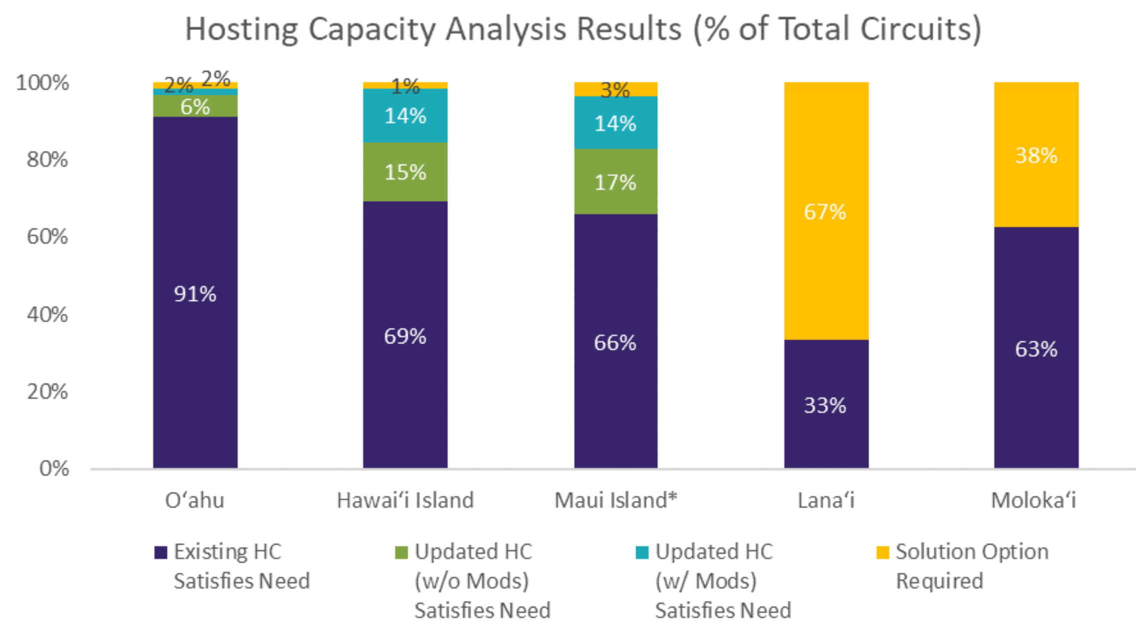

Figure 8: Summary of Hosting Capacity Results (% of Total Circuits) Using the Base DER Forecast[28]

[28] Total percentage does not equal to 100 % due to rounding.

3.5.3 Low DER Forecast

Of the 620 circuits assessed, 517 circuits are able to accommodate the total anticipated DER in 2025 with the existing hosting capacity using the base DER forecast. In addition, 53 circuits are able to accommodate the anticipated DER through an updated hosting capacity without grid needs. The remaining 50 circuits are identified as requiring grid needs and are discussed in the Section 4.

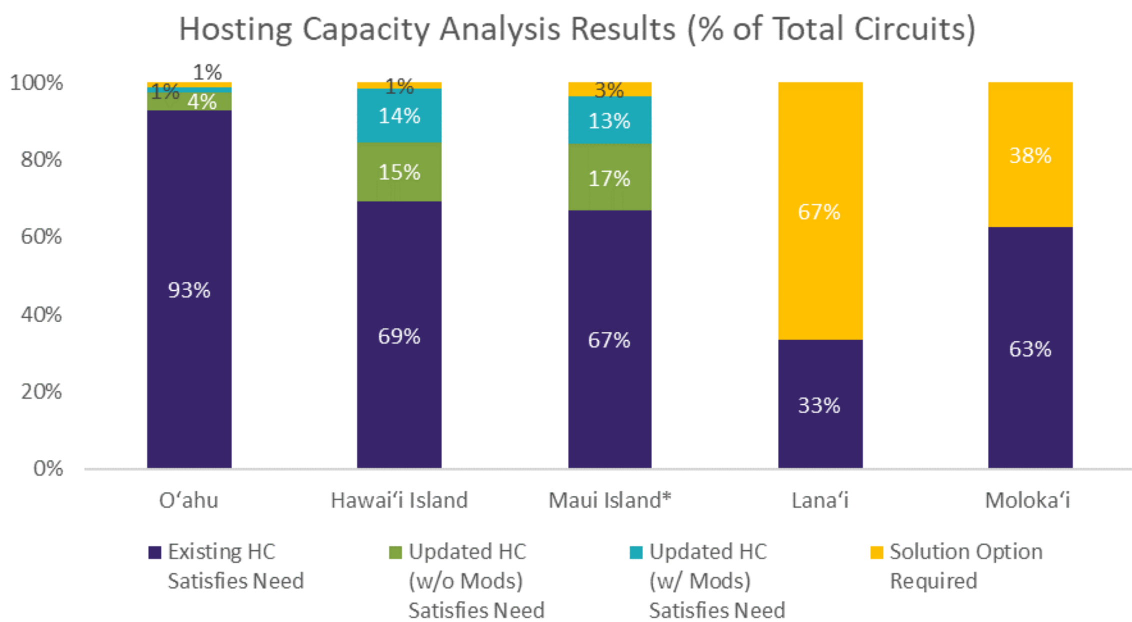

Figure 9: Summary of Hosting Capacity Results (% of Total Circuits) Using the Low DER Forecast[29]

[29] Total percentage does not equal to 100 % due to rounding.

4 Grid Needs

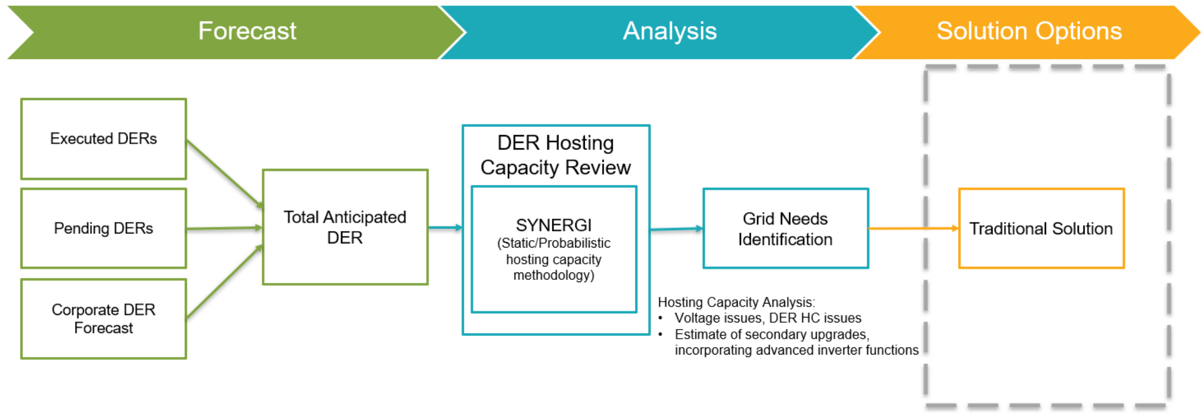

Figure 10: Solution Options Stage of the Distribution Planning Process

This section describes the last step to identify distribution grid needs:

1. Determine the annual anticipated DER (kW) by circuit.
2. Screen circuits for analysis.
3. Perform substation transformer and circuit-level hosting capacity analysis.
4. **Identify grid needs and solution options.**

Grid needs are identified for circuits requiring mitigation resulting from the hosting capacity analysis described in Section 3. A circuit is flagged as requiring mitigation if the hosting capacity is unable to accommodate the anticipated DER in 2025. For these circuits, the annual anticipated DER for each year for the study period (year 2021 through 2025) is compared to the hosting capacity. The earliest year that the anticipated DER is greater than the hosting capacity is identified as the year in which mitigation is required (i.e. operating date). A comparison of the annual anticipated DER to updated hosting capacity by circuit for each island is provided in the workbooks described in Appendix A:.[30]

[30] Workbooks are available on the Company website at: https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/key-stakeholder-documents

As described in the *Distribution Planning Methodology*, a traditional solution will be defined for each grid need identified and include:[31]

- **Substation**: Transformer asset identification
- **Circuit**: Feeder asset identification
- **Distribution Service Required**: Hosting Capacity, Distribution Capacity or Distribution Reliability (Back-Tie) Service
- **Primary Driver of Grid Need**: Defines whether the identified grid need is primarily driven by DER growth, demand growth, other factor(s), or a combination of factors
- **Violation Type**: Thermal and/or voltage violation that triggers the grid need
- **Operating Date**: The date at which traditional infrastructure must be constructed and energized, in advance of the forecasted grid need to maintain safety and reliability
- **Traditional Solution**: Traditional solution identified for mitigation (Solution Options)
- **Cost Estimate**: Estimated cost to provide traditional solution identified.

The hosting capacity grid needs assessment tables shown in the following sections are simplified and do not include all the fields defined above as some are not applicable for the hosting capacity grid needs or the fields are consistent for all islands for all years. The following fields are applicable to all islands and are not replicated in the tables in the subsequent sections:

- Distribution Service Required: Increase circuit hosting capacity
- Primary Driver of Grid Need: DER growth

For the circuits identified in Section 3.5 as requiring grid needs, some have solution options which can be addressed through modifications to existing equipment while others require infrastructure investments. For the solutions that do not require infrastructure investments (non-infrastructure investments), the cost to implement is minimal and therefore not provided in the following sections. These modifications include:

- LTC Settings Change: Adjusting the load tap changer ("LTC") on an existing transformer or regulator

[31] Hawaiian Electric, *Distribution Planning Methodology*, June 2020 at 20.

Circuits requiring infrastructure investments may include:

- Circuit phase balancing
- Dynamic LTC[32]
- New line voltage regulator
- New tie switch
- Reconductoring
- Step-down transformer upgrade

For these circuits, high-level cost estimates based on unit cost information from previous similar projects are provided.

A summary of the circuits requiring grid needs by solution type is shown below for each scenario. The number of circuits requiring grid needs is highest using the high DER forecast and decreases further using the base and low DER forecasts, respectively. Some circuits may require grid needs in two or more scenarios. Grid needs by circuit by scenario are provided in the following sections.

[32] Dynamic LTC is the ability to autonomously adjust the LTC setting of a transformer throughout the day based on triggers such as time of day or irradiance.

Table 4-1: Grid Needs Assessment Summary

Island	Forecast	Solution Option		Total Circuits
		Non-Infrastructure Investments[33]	Infrastructure Investments	
O'ahu	High	15	17	32
	Base	6	6	12
	Low	5	5	10
Hawai'i Island	High	32	2	34
	Base	19	2	21
	Low	19	2	21
Maui Island	High	13	7	20
	Base	12	3	15
	Low	11	3	14
Lana'i	High	–	2	2
	Base	–	2	2
	Low	–	2	2
Moloka'i	High	–	5	5
	Base	–	3	3
	Low	–	3	3
Total (All Islands)	High	60	33	93
	Base	37	16	53
	Low	35	15	50

[33] LTC settings changes only.

4.1 HIGH DER FORECAST

Using the high DER forecast, of the 93 circuits identified as requiring grid needs in Section 3.5.1, 60 circuits have solution options that can be addressed through minimal infrastructure investments (e.g. LTC settings change) and 33 circuits require infrastructure investments.

Table 4-2: Grid Needs Assessment Summary Using the High DER Forecast

Island	Total Circuits[34]	Violation Type[35]		Solution Option	
		Voltage	Conductor Overload	Non-Infrastructure Investments[36]	Infrastructure Investments
O'ahu	32	31	5	15	17
Hawai'i Island	34	34	-	32	2
Maui Island	20	19	2	13	7
Lana'i	2	2	-	-	2
Moloka'i	5	5	-	-	5
Total (All Islands)	93	91	7	60	33

The grid needs assessment by island by circuit are detailed in the following tables.

O'ahu

Table 4-3: O'ahu Grid Needs Assessment Using the High DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
AIEA 2	AIEA	Voltage	2022	LTC setting change	-
WAILUPE	AINA KOA	Voltage	2022	Circuit phase balancing	$14,400
KAMILOIKI	ANUU	Voltage	2023	LTC setting change	-
KAPAHULU 4	DIAMOND HEAD	Voltage	2022	LTC setting change	-

34 "Total Circuits" represents the number of circuits that have grid needs requirements.

35 Circuit totals by violation type do not match the total circuits column as some circuits have both voltage and conductor overload violations and are counted in both columns.

36 LTC settings changes only.

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
EWA BEACH 2	EWA BEACH 3	Voltage	2023	LTC setting change	-
EWA BEACH 2	EWA BEACH 4	Voltage	2023	LTC setting change	-
KAHALA 2 4KV	FARMERS RD	Voltage, conductor overloading	2023	Circuit phase balancing, Install two 3ph line regulators, Reconductoring	$605,191
WAIALUA 2	KAENA PT	Voltage	2023	LTC setting change	-
KAHALA 1 4KV	KAHALA	Voltage, conductor overloading	2022	Install 3ph line regulator, Reconductoring, new tie switch	$1,206,917
KEOLU 2	KAILUA HTS	Voltage	2025	LTC setting change	-
KALAMA 1 4KV	KAINALU	Voltage, conductor overloading	2021	Dynamic LTC, Install two 1ph line regulators, Reconductoring	$439,727
AIKAHI 1	KALAHEO	Voltage	2025	LTC setting change	-
WAIALUA 3	KAWAILOA	Voltage	2021	LTC setting change	-
KAHALA 2 4KV	KILAUEA 4KV	Voltage	2022	Circuit phase balancing and Install 3ph line regulator	$213,600
KAHALA 2 4KV	KOLOA	Voltage, conductor overloading	2024	Circuit phase balancing, Install 3ph line regulator, Reconductoring	$470,854
KUILIMA 2	KUILIMA 1	Voltage	2025	LTC setting change	-
WOODLAWN 2	LOWREY	Voltage	2023	Install two 1ph line regulators	$140,000
MAKAKILO 2	MAKAKILO 2	Voltage	2022	LTC setting change	-
PIIKOI 3	MANOA-PIIKOI	Voltage	2024	Circuit phase balancing	$3,600
MAKAHA 2	MAUKA	Voltage	2023	Circuit phase balancing	$3,600
MIKILUA 2	MIKILUA 3	Voltage	2023	Circuit phase balancing	$3,600

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
MIKILUA 2	MIKILUA 4	Voltage, transformer overloading	2021	Step-down transformer upgrade	$68,000
MIKILUA 3	MIKILUA 5	Voltage	2023	Dynamic LTC	$154,000
KALAMA 1 4KV	ONEAWA	Voltage	2022	LTC setting change	-
PAUOA 1	PAUOA 2	Voltage	2023	Circuit phase balancing and partial 4kV-12kV conversion	$610,200
PIIKOI 4	PIIKOI 8	Conductor overloading	2022	Reconductoring	$270,000
AHI 2	PORTLOCK	Voltage	2024	LTC setting change	-
WAIALUA 3	WAIALUA	Voltage	2022	LTC setting change	-
WAILUPE	WAILUPE	Voltage	2023	Circuit phase balancing	$7,200
WAIMANALO BCH 1	WAIMANALO	Voltage	2025	Dynamic LTC	$154,000
WAIMEA 1	WAIMEA 2	Voltage	2024	LTC setting change	-
WAIALAE 1 4KV	WAI-WILHELMINA	Voltage	2025	Install two 1ph line regulators	$140,000

Hawaiʻi Island

Table 4-4: Hawaii Island Grid Needs Assessment Using the High DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Captain Cook	Captain Cook 12	Voltage	2025	LTC setting change	-
Halaula	Halaula 1	Voltage	2022	Install two 3ph line regulator	$420,000
Hawaiian Paradise Park 2	Hawaiian Paradise Park 13	Voltage	2021	LTC setting change	-
Hawaiian Paradise Park 2	Hawaiian Paradise Park 14	Voltage	2021	LTC setting change	-

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Honokaa 2	Honokaa 12	Voltage	2021	LTC setting change	–
Huehue	Huehue 11	Voltage	2024	LTC setting change	–
Kahaluu 1	Kahaluu 11	Voltage	2025	LTC setting change	–
Kaloko 2	Kaloko 13	Voltage	2025	LTC setting change	–
Kapua 1	Kapua 11	Voltage	2021	LTC setting change	–
Kauhale	Kauhale 11	Voltage	2021	LTC setting change	–
Kauhale	Kauhale 12	Voltage	2021	LTC setting change	–
Kaumana	Kaumana 11	Voltage	2025	LTC setting change	–
Kawaihae	Kawaihae 11	Voltage	2024	LTC setting change	–
Kawaihae	Kawaihae 12	Voltage	2025	LTC setting change	–
Keahole Airport	Keahole Airport 11	Voltage	2022	LTC setting change	–
Keahole Airport	Keahole Airport 12	Voltage	2025	LTC setting change	–
Keahole Airport	Keahole Airport 13	Voltage	2024	LTC setting change	–
Komohana 1	Komohana 12	Voltage	2021	LTC setting change	–
Kuakini 1	Kuakini 11	Voltage	2023	LTC setting change	–
Kurtistown	Kurtistown 12	Voltage	2021	LTC setting change	–
Laupahoehoe	Laupahoehoe 2	Voltage	2022	LTC setting change	–
Mauna Lani 2	Mauna Lani 14	Voltage	2021	LTC setting change	–
Namakani Paio	Namakani Paio	Voltage	2021	LTC setting change	–
Ookala	Ookala	Voltage	2021	LTC setting change	–
Orchid Isle	Orchid Isle 11	Voltage	2021	LTC setting change	–
Orchid Isle	Orchid Isle 12	Voltage	2021	LTC setting change	–
Paauilo	Paauilo 1	Voltage	2021	LTC setting change	–
Panaewa	Panaewa 12	Voltage	2021	LTC setting change	–
Puueo 2	Puueo 11	Voltage	2021	LTC setting change	–
Puueo 2	Puueo 12	Voltage	2021	LTC setting change	–

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Puuwaawaa	Puuwaawaa 11	Voltage	2021	Install 3ph line regulator	$210,000
Waikii	Waikii 12	Voltage	2021	LTC setting change	-
Waikoloa	Waikoloa 12	Voltage	2022	LTC setting change	-
Waipunahina	Waipunahina 11	Voltage	2022	LTC setting change	-

Maui Island

Table 4-5: Maui Island Grid Needs Assessment Using the High DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Huelo	Huelo 74A/Huelo	Voltage	2024	Install 1ph line regulator	$70,000
Kahului 4	Kahului 8/4048	Voltage	2024	LTC setting change	-
Kahului 5	Kahului 8/4049	Voltage	2021	LTC setting change	-
Kauhikoa	Kauhikoa 98/1295	Voltage	2025	LTC setting change	-
Kihei 4	Kihei 35/1515	Voltage	2023	Install 3ph line regulator	$210,000
Kuau	Kuau 73/4066	Voltage	2021	LTC setting change	-
Kuihelani	Kuihelani 209/1653	Voltage	2021	LTC setting change	-
Kuihelani	Kuihelani 209/1708	Voltage	2021	LTC setting change	-
Kula	Kula 13/1237	Voltage, conductor overloading	2021	Reconductor and Install two 3ph line regulators	$2,235,909
Kula	Kula 13/1238	Voltage	2023	LTC setting change	-
Lahaina 5	Lahaina 34/1398	Voltage	2021	Install 3ph line regulator	$210,000

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Makawao	Makawao 12/1236	Voltage	2023	LTC setting change	-
Onehee	Onehee 40/4055	Conductor overloading	2025	Reconductor	$560,000
Paia Mauka	Paia Mauka 93/4042	Voltage	2021	Circuit phase balancing	$14,400
Peahi	Peahi 94/1294	Voltage	2021	LTC setting change	-
Pukalani 1	Pukalani 17/1282	Voltage	2022	LTC setting change	-
Spreckelsville	Spreckelsville 92/4043	Voltage	2021	LTC setting change	-
Waiinu 3	Waiinu 36/1493	Voltage	2022	LTC setting change	-
Wailea 4	Wailea 25/1517	Voltage	2022	Circuit phase balancing	$14,400
Wailea 4	Wailea 25/1518	Voltage	2022	LTC setting change	-

Lana‘i

Table 4-6: Lanai Grid Needs Assessment Using the High DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Miki Basin	Miki Basin PP 302/1208	Voltage	2023	Install 3ph line regulator	$252,000
Miki Basin	Miki Basin PP 302/1210	Voltage	2022	Install 3ph line regulator	$252,000

Moloka'i

Table 4-7: Molokai Grid Needs Assessment Using the High DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Palaau	Palaau PP 81/105A	Voltage	2022	Install 3ph line regulator	$252,000
Palaau	Palaau PP 81/106B	Voltage	2023	Install 3ph line regulator	$252,000
Palaau	Palaau PP 81/109B	Voltage	2021	Install 3ph line regulator	$252,000
Palaau	Palaau PP 81/110B	Voltage	2021	Install 3ph line regulator	$252,000
Palaau	Palaau PP 81/111A	Voltage	2021	Install three 3ph line regulator	$756,000

4.2 BASE DER FORECAST

Using the base DER forecast, of the 53 circuits identified as requiring grid needs in Section 3.5.2, 37 circuits have solution options that can be addressed through minimal infrastructure investments (e.g. LTC settings change) and 16 circuits require infrastructure investments.

Table 4-8: Grid Needs Assessment Summary Using the Base DER Forecast

Island	Total Circuits[37]	Violation Type[38]		Solution Option	
		Voltage	Conductor Overload	Non-Infrastructure Investments[39]	Infrastructure Investments
O'ahu	12	11	1	6	6
Hawai'i Island	21	21	-	19	2
Maui Island	15	15	1	12	3

37 "Total Circuits" represents the number of circuits that have grid needs requirements.

38 Circuit totals by violation type do not match the total circuits column as some circuits have both voltage and conductor overload violations and are counted in both columns.

39 LTC settings changes only.

Island	Total Circuits[37]	Violation Type[38]		Solution Option	
		Voltage	Conductor Overload	Non-Infrastructure Investments[39]	Infrastructure Investments
Lana'i	2	2	–	–	2
Moloka'i	3	3	–	–	3
Total (All Islands)	53	52	2	37	16

The grid needs assessment by island by circuit are detailed in the following tables.

O'ahu

Table 4-9: O'ahu Grid Needs Assessment Using the Base DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
AIEA 2	AIEA	Voltage	2024	LTC setting change	–
WAILUPE	AINA KOA	Voltage	2023	Circuit phase balancing	$7,200
KAPAHULU 4	DIAMOND HEAD	Voltage	2024	LTC setting change	–
KALAMA 1 4KV	KAINALU	Voltage	2021	Dynamic LTC, Install two 1ph line regulators	$294,000
WAIALUA 3	KAWAILOA	Voltage	2021	LTC setting change	–
KAHALA 2 4KV	KILAUEA 4KV	Voltage	2023	Circuit phase balancing and Install 3ph line regulator	$213,600
MAKAKILO 2	MAKAKILO 2	Voltage	2023	LTC setting change	–
PIIKOI 3	MANOA-PIIKOI	Voltage	2023	Circuit phase balancing and LTC setting change	$3,600
MAKAHA 2	MAUKA	Voltage	2023	Circuit phase balancing	$3,600
KALAMA 1 4KV	ONEAWA	Voltage	2024	LTC setting change	–
PIIKOI 4	PIIKOI 8	Conductor overloading	2023	Reconductoring	$270,000
WAIALUA 3	WAIALUA	Voltage	2021	LTC setting change	–

Hawaiʻi Island

Table 4-10: Hawaii Island Grid Needs Assessment Using the Base DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Halaula	Halaula 1	Voltage	2024	Install two 3ph line regulator	$420,000
Hawaiian Paradise Park 2	Hawaiian Paradise Park 13	Voltage	2021	LTC setting change	-
Hawaiian Paradise Park 2	Hawaiian Paradise Park 14	Voltage	2021	LTC setting change	-
Honokaa 2	Honokaa 12	Voltage	2022	LTC setting change	-
Kapua 1	Kapua 11	Voltage	2021	LTC setting change	-
Kauhale	Kauhale 11	Voltage	2021	LTC setting change	-
Kauhale	Kauhale 12	Voltage	2021	LTC setting change	-
Keahole Airport	Keahole Airport 11	Voltage	2024	LTC setting change	-
Komohana 1	Komohana 12	Voltage	2021	LTC setting change	-
Kurtistown	Kurtistown 12	Voltage	2021	LTC setting change	-
Laupahoehoe	Laupahoehoe 2	Voltage	2022	LTC setting change	-
Namakani Paio	Namakani Paio	Voltage	2021	LTC setting change	-
Ookala	Ookala	Voltage	2021	LTC setting change	-
Orchid Isle	Orchid Isle 11	Voltage	2021	LTC setting change	-
Orchid Isle	Orchid Isle 12	Voltage	2021	LTC setting change	-
Paauilo	Paauilo 1	Voltage	2021	LTC setting change	-
Panaewa	Panaewa 12	Voltage	2021	LTC setting change	-
Puueo 2	Puueo 11	Voltage	2021	LTC setting change	-
Puueo 2	Puueo 12	Voltage	2021	LTC setting change	-
Puuwaawaa	Puuwaawaa 11	Voltage	2021	Install 3ph line regulator	$210,000
Waikoloa	Waikoloa 12	Voltage	2022	LTC setting change	-

Maui Island

Table 4-11: Maui Island Grid Needs Assessment Using the Base DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Kahului 5	Kahului 8/4049	Voltage	2021	LTC setting change	-
Kihei 4	Kihei 35/1515	Voltage	2025	LTC setting change	-
Kuau	Kuau 73/4066	Voltage	2021	LTC setting change	-
Kuihelani	Kuihelani 209/1653	Voltage	2021	LTC setting change	-
Kuihelani	Kuihelani 209/1708	Voltage	2021	LTC setting change	-
Kula	Kula 13/1237	Voltage, conductor overloading	2022	Reconductor and Install two 3ph line regulators	$2,235,909
Kula	Kula 13/1238	Voltage	2025	LTC setting change	-
Lahaina 5	Lahaina 34/1398	Voltage	2021	Install 3ph line regulator	$210,000
Paia Mauka	Paia Mauka 93/4042	Voltage	2021	Circuit phase balancing	$3,600
Peahi	Peahi 94/1294	Voltage	2021	LTC setting change	-
Pukalani 1	Pukalani 17/1282	Voltage	2022	LTC setting change	-
Spreckelsville	Spreckelsville 92/4043	Voltage	2021	LTC setting change	-
Waiinu 3	Waiinu 36/1493	Voltage	2022	LTC setting change	-
Wailea 4	Wailea 25/1517	Voltage	2023	LTC setting change	-
Wailea 4	Wailea 25/1518	Voltage	2023	LTC setting change	-

Lanaʻi

Table 4-12: Lanai Grid Needs Assessment Using the Base DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Miki Basin	Miki Basin PP 302/1208	Voltage	2023	Install 3ph line regulator	$252,000
Miki Basin	Miki Basin PP 302/1210	Voltage	2023	Install 3ph line regulator	$252,000

Molokaʻi

Table 4-13: Molokai Grid Needs Assessment Using the Base DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Palaau	Palaau PP 81/109B	Voltage	2023	Install 3ph line regulator	$252,000
Palaau	Palaau PP 81/110B	Voltage	2021	Install 3ph line regulator	$252,000
Palaau	Palaau PP 81/111A	Voltage	2021	Install three 3ph line regulator	$756,000

4.3 LOW DER FORECAST

Using the low DER forecast, of the 50 circuits identified as requiring grid needs in Section 3.5.3, 35 circuits have solution options that can be addressed through minimal infrastructure investments (e.g. LTC settings change) and 15 circuits require infrastructure investments.

Table 4-14: Grid Needs Assessment Summary Using the Low DER Forecast

Island	Total Circuits[40]	Violation Type[41]		Solution Option	
		Voltage	Conductor Overload	Non-Infrastructure Investments[42]	Infrastructure Investments
O‘ahu	10	9	1	5	5
Hawai‘i Island	21	21	-	19	2
Maui Island	14	14	1	11	3
Lana‘i	2	2	-	-	2
Moloka‘i	3	3	-	-	3
Total (All Islands)	50	49	2	35	15

The grid needs assessment by island by circuit are detailed in the following tables.

O‘ahu

Table 4-15: O‘ahu Grid Needs Assessment Using the Low DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
WAILUPE	AINA KOA	Voltage	2024	Circuit phase balancing	$7,200
KALAMA 1 4KV	KAINALU	Voltage	2021	Dynamic LTC	$154,000
AIKAHI 1	KALAHEO	Voltage	2023	LTC setting change	-
WAIALUA 3	KAWAILOA	Voltage	2021	LTC setting change	-

40 "Total Circuits" represents the number of circuits that have grid needs requirements.

41 Circuit totals by violation type do not match the total circuits column as some circuits have both voltage and conductor overload violations and are counted in both columns.

42 LTC settings changes only.

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
KAHALA 2 4KV	KILAUEA 4KV	Voltage	2024	Circuit phase balancing and Install 3ph line regulator	$213,600
MAKAKILO 2	MAKAKILO 2	Voltage	2023	LTC setting change	-
MAKAHA 2	MAUKA	Voltage	2023	Circuit phase balancing	$3,600
KALAMA 1 4KV	ONEAWA	Voltage	2024	LTC setting change	-
PIIKOI 4	PIIKOI 8	Conductor overloading	2025	Reconductoring	$270,000
WAIALUA 3	WAIALUA	Voltage	2022	LTC setting change	-

Hawaiʻi Island

Table 4-16: Hawaii Island Grid Needs Assessment Using the Low DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Halaula	Halaula 1	Voltage	2024	Install two 3ph line regulator	$420,000
Hawaiian Paradise Park 2	Hawaiian Paradise Park 13	Voltage	2021	LTC setting change	-
Hawaiian Paradise Park 2	Hawaiian Paradise Park 14	Voltage	2021	LTC setting change	-
Honokaa 2	Honokaa 12	Voltage	2022	LTC setting change	-
Kapua 1	Kapua 11	Voltage	2021	LTC setting change	-
Kauhale	Kauhale 11	Voltage	2021	LTC setting change	-
Kauhale	Kauhale 12	Voltage	2021	LTC setting change	-
Keahole Airport	Keahole Airport 11	Voltage	2024	LTC setting change	-
Komohana 1	Komohana 12	Voltage	2021	LTC setting change	-
Kurtistown	Kurtistown 12	Voltage	2021	LTC setting change	-

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Laupahoehoe	Laupahoehoe 2	Voltage	2022	LTC setting change	-
Namakani Paio	Namakani Paio	Voltage	2021	LTC setting change	-
Ookala	Ookala	Voltage	2021	LTC setting change	-
Orchid Isle	Orchid Isle 11	Voltage	2021	LTC setting change	-
Orchid Isle	Orchid Isle 12	Voltage	2021	LTC setting change	-
Paauilo	Paauilo 1	Voltage	2021	LTC setting change	-
Panaewa	Panaewa 12	Voltage	2021	LTC setting change	-
Puueo 2	Puueo 11	Voltage	2021	LTC setting change	-
Puueo 2	Puueo 12	Voltage	2021	LTC setting change	-
Puuwaawaa	Puuwaawaa 11	Voltage	2021	Install 3ph line regulator	$210,000
Waikoloa	Waikoloa 12	Voltage	2022	LTC setting change	-

Maui Island

Table 4-17: Maui Island Grid Needs Assessment Using the Low DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Kahului 5	Kahului 8/4049	Voltage	2021	LTC setting change	-
Kuau	Kuau 73/4066	Voltage	2021	LTC setting change	-
Kuihelani	Kuihelani 209/1653	Voltage	2021	LTC setting change	-
Kuihelani	Kuihelani 209/1708	Voltage	2021	LTC setting change	-
Kula	Kula 13/1237	Voltage, conductor overloading	2022	Reconductor and Install two 3ph line regulators	$2,235,909
Kula	Kula 13/1238	Voltage	2025	LTC setting change	-

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Lahaina 5	Lahaina 34/1398	Voltage	2021	Install 3ph line regulator	$210,000
Paia Mauka	Paia Mauka 93/4042	Voltage	2021	Circuit phase balancing	$3,600
Peahi	Peahi 94/1294	Voltage	2021	LTC setting change	-
Pukalani 1	Pukalani 17/1282	Voltage	2022	LTC setting change	-
Spreckelsville	Spreckelsville 92/4043	Voltage	2021	LTC setting change	-
Waiinu 3	Waiinu 36/1493	Voltage	2023	LTC setting change	-
Wailea 4	Wailea 25/1517	Voltage	2023	LTC setting change	-
Wailea 4	Wailea 25/1518	Voltage	2023	LTC setting change	-

Lana‘i

Table 4-18: Lanai Grid Needs Assessment Using the Low DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Miki Basin	Miki Basin PP 302/1208	Voltage	2023	Install 3ph line regulator	$252,000
Miki Basin	Miki Basin PP 302/1210	Voltage	2022	Install 3ph line regulator	$252,000

Moloka'i

Table 4-19: Molokai Grid Needs Assessment Using the Low DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Palaau	Palaau PP 81/109B	Voltage	2023	Install 3ph line regulator	$252,000
Palaau	Palaau PP 81/110B	Voltage	2021	Install 3ph line regulator	$252,000
Palaau	Palaau PP 81/111A	Voltage	2021	Install three 3ph line regulator	$756,000

5 Summary and Next Steps

With the use of advanced tools and analysis (e.g., LoadSEER and Synergi), the Company has been able to do a wide-scale update of the available hosting capacity on all primary distribution circuits, as well as determine which circuits require further analysis to accommodate the total anticipated DER in year 2025.

Using the high DER forecast, the analysis finds:

- 527 circuits do not require grid needs:
  - 435 circuits can accommodate the 5-year DER forecast with existing hosting capacity.
  - 92 circuits can accommodate the 5-year DER forecast through updated hosting capacity without modifications.
- 93 circuits require grid needs at the primary distribution circuit-level:
  - 60 circuits can accommodate through minimal investment (e.g., LTC setting changes).
  - 33 circuits require solutions/mitigations, which will serve as an input to the Grid Needs Assessment stage of the IGP process. Total estimated costs for traditional solutions on all islands is $10.7 M.

Updated hosting capacities and implementation of the above mitigations and solutions will provide an increase of hosting capacity of 64 MW on O'ahu, 37 MW on Hawai'i Island, 64 MW on Maui Island, 0.17 MW on Lana'i, and 1.4 MW on Moloka'i.[43]

Using the base DER forecast, the analysis finds:

- 567 circuits do not require grid needs:
  - 509 circuits can accommodate the 5-year DER forecast with existing hosting capacity.
  - 58 circuits can accommodate the 5-year DER forecast through updated hosting capacity without modifications.
- 53 circuits require grid needs at the primary distribution circuit-level:
  - 37 circuits can accommodate through minimal investment (e.g., LTC setting changes).

[43] Hosting capacity increases quantified are circuit-level hosting capacity only and not representative of the system-level hosting capacity which may be lower due to system-level constraints that are not evaluated during this process.

- 16 circuits require solutions/mitigations, which will serve as an input to the Grid Needs Assessment stage of the IGP process. Total estimated costs for traditional solutions on all islands is $5.6 M.

Updated hosting capacities and implementation of the above mitigations and solutions will provide an increase of hosting capacity of 27 MW on O'ahu, 20 MW on Hawai'i Island, 47 MW on Maui Island, 0.04 MW on Lana'i, and 0.5 MW on Moloka'i.[43]

Using the low DER forecast, the analysis finds:

- 570 circuits do not require grid needs:
    - 517 circuits can accommodate the 5-year DER forecast with existing hosting capacity.
    - 53 circuits can accommodate the 5-year DER forecast through updated hosting capacity without modifications.
- 50 circuits require grid needs at the primary distribution circuit-level:
    - 35 circuits can accommodate through minimal investment (e.g., LTC setting changes).
    - 15 circuits require solutions/mitigations, which will serve as an input to the Grid Needs Assessment stage of the IGP process. Total estimated costs for traditional solutions on all islands is $5.5 M.

Updated hosting capacities and implementation of the above mitigations and solutions will provide an increase of hosting capacity of 22 MW on O'ahu, 20 MW on Hawai'i Island, 45 MW on Maui Island, 0.04 MW on Lana'i, and 0.5 MW on Moloka'i.[43]

Consistent with the *Non-Wires Opportunity Evaluation Methodology*,[44,45] cost estimates are developed for solutions that require significant upgrades. These estimates will be used as inputs to the Grid Needs Assessment stage of the IGP process to evaluate if they qualify as an NWA opportunity, and if so, be procured as part of the overarching IGP process where a portfolio of solutions will be selected to address the identified grid needs.

[44] Hawaiian Electric, Non-Wires Opportunity Evaluation Methodology June 2020, https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/distribution_planning/20200602_dpwg_non_wires_opportunity_evaluation_methodology.pdf

[45] Concurrent to this filing, an update to the Non-Wires Opportunity Evaluation Methodology was filed in the Grid Needs Assessment (Nov. 2021, Dkt. No. 2018-0165). References in this document are made to the document in footnote 52.

Appendix A: Workbook Index

The DER forecasts, hosting capacity analysis, and grid needs for each scenario by island are available on the Company's website in Excel workbooks as the tables are too voluminous to provide in table format herein.[46]

A summary of the workbooks is provided below.

Table A-1: Distribution DER Hosting Capacity Grid Needs Workbook Index

Scenario	Modeling Case	DER Forecast	Workbook[47]
1	Base	Base Forecast	Distribution DER Hosting Capacity Grid Needs Base Forecast (EXCEL) (November 2021)
2	High Load Customer Technology Adoption Bookend	Low Forecast	Distribution DER Hosting Capacity Grid Needs Low Forecast (EXCEL) (November 2021)
3	Low Load Customer Technology Adoption Bookend	High Forecast	Distribution DER Hosting Capacity Grid Needs High Forecast (EXCEL) (November 2021)

[46] *See* https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/key-stakeholder-documents

[47] File name as it appears on the Company website.

Appendix B: Stakeholder Engagement

The Company recognizes stakeholder engagement as an integral part of the IGP process. In an effort to proactively solicit stakeholder feedback on this report, the Company provided a preliminary report, the October 2021 Update, to stakeholders for review and comment on October 1, 2021. The Company subsequently met with the STWG on October 6, 2021 to address questions and receive feedback from the stakeholders. Meeting minutes capturing feedback from the discussion and presentation materials from the meeting can be found on the IGP website.[48]

Additionally, the Company received feedback from various Organizations which is consolidated anonymously below. Feedback from stakeholders in this section are shown in **bold**, and the Company's response to the questions or feedback are shown in *italics*.

1. **Does Hawaiian Electric plan to run the Hosting Capacity analysis with variations of forecast layers other than DERs (i.e. EoT adoption, EE, etc.)?**

   Hawaiian Electric does not plan to run the HC analysis with variations of forecast layers other than DERs. Different variations of forecast layers for EoT and EE were included with the Locational Forecast report.

2. **At 9, Hawaiian Electric states, "This document focuses on hosting capacity grid needs identified for the next five years (year 2021 through 2025) driven by the forecast DER growth on distribution circuits…" How often will Hawaiian Electric update this distribution hosting capacity?**
   a. **Will updates occur every five years to align with the timeline analyzed in this analysis, or will updates occur along with the shorter IGP cycle?**

[48] *See* https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/stakeholder-technical-documents

Distribution circuit hosting capacity numbers are updated in the Locational Value Map ("LVM")[49] as technical reviews for DER applications are performed. Hosting capacity grid needs will be updated with each IGP cycle.

b. **In light of the RESOLVE and PLEXOS modeling using 2025 as a start year, how will mid-term distribution grid-needs (2025-2030) and long-term distribution grid needs (beyond 2030) be integrated into the IGP process?**

Identifying distribution grid needs beyond five years is highly uncertain as developers do not have concrete plans more than 3-5 years in advance. Therefore, the Company would not identify needs that lead to distribution grid investments more than 5 years before it is expected to be needed.

3. **At 15, HECO states, "This 30MW of CBRE Phase 2 small projects were included by adding 6 MW per year to the corporate DER forecast. This was done for each scenario: Base, Low, and High. This amount is divided into residential and commercial customer types and is used as the system level DER limit for the spatial allocation in LoadSEER." Please clarify whether the 30 MW of CBRE is the total system level DER limit for the spatial allocation in LoadSEER, or whether this is added to the corporate forecast. Additionally, please clarify why splitting commercial and residential unnecessary for this HCA.**

The 30 MW of CBRE is added in addition to the corporate DER forecast. For the hosting capacity analysis, the amount of commercial and residential DERs that were allocated on each circuit were added together to determine the total forecasted DER on the circuit. Splitting the commercial and residential PV is unnecessary because the impact to hosting capacity is the same.

[49] LVMs for each island are available on the Company website at: https://www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/locational-value-maps.

4. **It would be helpful to clarify (or re-describe) what "total circuits" represents in Table 4.**

   In Table 4,[50] *the "Total Circuits" represents the number of circuits that have grid needs requirements for the high DER forecast scenario.*[51]

5. **For Tables 5-9 (at 28-34), how did Hawaiian Electric develop cost estimates for solutions to expand hosting capacity requiring infrastructure investments?**

   The cost estimates in Tables 5-9[52] *are high-level estimates using unit costs based on previous similar projects.*[53]

6. **At 21, it is explained that "the hosting capacity is determined for a snapshot in time, specifically the hour representing the daytime minimum load ("DML")". Out of what time-series data are the daytime minimum load and peak demand hours selected (i.e. from 8760 hours for a given year, for multiple years, from a representative day in each month, etc.)?**

   Generally, the previous year's 8760 data (i.e., year 2020) was used to select daytime minimum or peak demand load hours. In cases where there may be missing data, an earlier year's data is used.

   a. **Did HECO consider looking at time periods other than the DML to perform the analysis?**

      Currently and in the near future, the DML time period represents the circuits' hosting capacity limit due to the high amounts of PV. As BESS penetration increases, other time periods will be analyzed.

[50] Table 4 in the October 2021 Update is relabeled as Table 4-2 in this report.

[51] See Section 4.1 High DER Forecast at 31.

[52] Tables 5 through 9 in the October 2021 Update are relabeled as Table 4-3 through Table 4-7 in this report.

[53] See Section 4 Grid Needs at 27.

b. **If so, what were the alternatives considered and what lead HECO to choosing to perform the analysis based on the DML?**

See response to 6.a.

7. **At 16, HECO explains that the forecasted DER growth is based on executed DER in selected programs and adjustments are made for large projects (including CBRE Phase 1, FIT, and large SIA) and for CBRE Phase 2 small projects. At 13, HECO states that battery energy storage capacity is not included in the aggregated DER values. Please confirm that the DER growth analyzes PV technology only.**

The DER growth for the hosting capacity analysis looked at PV technology only. Energy storage profiles were removed from the executed DER amount as they are not expected to export coincidentally with DGPV. The analysis focused on hosting capacity during the day. However, the intent is to move toward a more time-based analysis to account for battery systems discharging at other times of the day as battery system penetration increases.

a. **If so, how was the load profile determined for the PV additions (i.e. a composite of historic profiles weighted across the different programs, one uniform PV profile, etc.)?**

Historical load measurements that include executed DERs were used to determine the load. Future PV additions up to the circuit hosting capacity were modeled at 100% rated capacity.

b. **If not, which different types of DERs make up the expected DER growth and how was the load profile determined for this mix of DERs?**

For this filing we considered DGPV growth and didn't account for the other layers in the hosting capacity analyses.

c. **If the DER growth forecast only analyzes PV technology, how will HECO account for the prevalence of paired solar plus storage systems plus other**

DERs such as EVs, EE, and DR equipment and their effect on circuit hosting capacity?

The locational forecast includes the Energy storage, EV, and EE layers. In the future these layers will be accounted through LoadSEER and the output files will be considered for analysis.