BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAIʻI

In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate Performance-Based Regulation.	DOCKET NO. 2018-0088

HAWAIIAN ELECTRIC COMPANIES' PHASE 5 OPENING BRIEF

EXHIBITS 1 THROUGH 2

AND

CERTIFICATE OF SERVICE

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In accordance with Order No. 41639, *Establishing a Briefing Schedule for Phase 5 of the Comprehensive Evaluation of the PBR Framework,* issued on April 4, 2025 ("Order 41639"), the Hawaiian Electric Companies[1] respectfully submit their Opening Brief which presents their preliminary positions regarding evaluation of the PBR Framework during the first multi-year rate period ("MRP1").[2, 3]

EXECUTIVE SUMMARY

As the Companies have previously stated, Hawai‘i PBR has strong foundational elements. Being the innovation that it is, the Commission contemplated from the outset that periodic review and potential adjustment was warranted.

[1] The "Hawaiian Electric Companies" or "Companies" are Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Hawai‘i Electric Light Company, Inc. ("Hawai‘i Electric Light") and Maui Electric Company, Limited ("Maui Electric") (collectively referred to also as "Hawaiian Electric").

[2] This Opening Brief focuses on responding to the questions posed in Order 41639 and will not address those issues already resolved through the Commission's Order No. 41575, *Addressing the Matter of Re-Basing Hawaiian Electric's Target Revenues for the Second Multi-Year Rate Period*, issued on February 27, 2025 ("Order 41575"), in this proceeding.

[3] The Companies' final positions on issues will be developed through the Phase 6 process of this proceeding which will "examine what specific modifications to selected PBR mechanisms should be considered" ahead of MRP2 and which will be contingent in part upon the final component design of MRP2 as well as the outcome of the re-basing process, evaluated on a comprehensive basis.

In this brief, the Companies address their performance under the PBR Framework during MRP1 and suggest areas for focus in considering changes for the second multi-year rate period ("MRP2"). In sum, the PBR Framework had somewhat mixed results in promoting priority outcomes during MRP1. Although the Companies realized significant achievements in certain areas, select changes to the Framework would improve support for more broadly obtaining desired results.

The planned consolidated rate case process will address several Hawaiian Electric concerns and set a new starting point for MRP2. Thus, the Companies' forward-looking comments focus predominantly on Framework changes for after new base rates are in effect.

The Companies are also acutely aware of the Commission's significant workload on many fronts. Thus, the Companies' view is that the PBR Working Group should center its efforts on a smaller number of potential Framework changes that will have meaningful impacts. Below, the Companies express their views on what those key changes should be.

I. How the Companies Have Performed Under the PBR Framework During MRP1: Financial Integrity and Opportunities.

In its Decision and Order in Phase 1 of the PBR proceeding, the Commission established utility financial integrity as a guiding principle to inform the development of PBR mechanisms. It stated that "[t]he financial integrity of the utility is essential to its basic obligation to provide safe and reliable electric service for its customers and a PBR framework is intended to preserve the utility's opportunity to earn a fair return on its business and investments, while maintaining attractive utility features, such as access to low-cost capital."[4] Credit ratings and return on equity ("ROE") are common measures to assess financial integrity.

[4] Decision and Order No. 36326, issued on May 23, 2019 in Docket No. 2018-0088, at 6 (footnote omitted).

A. Credit Rating Metric: Initial Positive Progress Was Overcome by Maui Wildfire Event; But Better Financial Performance Was Going to Be Necessary to Improve Credit Ratings Before Then

The following is a history of Hawaiian Electric's credit ratings during MRP1 as reported on the Companies' website under performance metrics:[5]

	Fitch		Moody's		S&P	
Year	Rating	Outlook	Rating	Outlook	Rating	Outlook
2025 (as of 3/31/25)	B	Stable	Ba3	Stable	B-	Positive (from 3/7/25) Negative
2024	B	Stable	Ba3	Stable	B-	Negative (from 11/22/24) Watch Negative (from 8/26/24) Negative
		(from 10/25/24)				(from 3/12/24)
2023	B	Watch Negative	Ba3	Stable (from 12/18/23) Review for Downgrade	B-	Watch Negative
	(from 8/21/23)	(from 8/21/23)		(from 9/8/23)	(from 8/24/23)	
	A-	Stable		Rating Under Review	BB-	Watch Negative
	(from 7/28/23)	(from 7/28/23)	(from 8/18/23)	(from 8/18/23)	(from 8/15/23)	(from 8/15/23)
2022	BBB+	Positive	Baa1	Stable	BBB	Stable
		(from 6/27/22)				
2021	BBB+	Stable	Baa1	Stable	BBB	Stable
			(from 4/20/21)	(from 4/20/21)	(from 3/17/21)	(from 3/17/21)

In MRP1, before the August 8, 2023 Maui Wildfire, the Companies began to see credit rating improvement from one of its rating agencies. In particular, Fitch upgraded Hawaiian Electric into the Upper Middle Grade rating range (A-) on July 28, 2023. In its report,[6] Fitch stated "the upgrade is supported by a more predictable regulatory construct in Hawaii implemented in 2021

[5] Source: https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/financial. Financial: Credit Ratings historical data.

[6] FitchRatings, *Fitch Upgrades HEI to 'BBB+' and HECO to 'A-'; Outlook is Stable*, dated July 28, 2023.

that provides a well-defined framework within which company can manage its capital improvements and O&M." Fitch views the PBR construct as "a credit positive as it provides a more stable framework for the utility to deliver on its earnings and cash flow, and should enable the utility to narrow the gap between allowed and earned ROEs in the next couple of years." Fitch recognized that "PBR kept in place most progressive regulatory rate-making mechanisms that smooth earnings such as sales decoupling, energy cost and purchased power recovery/adjustment clauses as well as a surcharge mechanism for the recovery of renewable energy and infrastructure capital investments." In addition, Fitch stated that "HECO's regulatory environment in Hawaii has been challenging in the past, but has become more predictable with the establishment of the PBR."

The other rating agencies had not yet adjusted Hawaiian Electric's rating. Nevertheless, a common theme from pre-Maui Wildfire agency reports was that positive rating improvement would depend in part on improvement of the Companies' ability to earn closer to their authorized ROEs. Both Moody's and S&P noted that an upgrade could be possible if Hawaiian Electric's financial measures improve. Moody's noted that "[w]e could take positive rating action on HECO if the company generates a CFO pre-WC to debt ratio above 20% on a sustained basis and continues with its progress on renewable energy transition."[7, 8] S&P noted "[w]e could upgrade HECO over the next 12-24 months if its financial measures improve, with FFO to debt consistently above 22%."[9, 10]

Thus, the credit rating metric was tied in part to the Companies' consolidated ROE performance, which has been persistently below Commission authorized levels during MRP1,

[7] Moody's Investor Service Credit Opinion, *Hawaiian Electric Company, Inc.*, dated January 9, 2023.
[8] "CFO pre-WC" stands for Cash Flow from Operations before Working Capital.
[9] S&P Global Ratings, RatingsDirect, *Hawaiian Electric Co.*, dated July 25, 2022.
[10] "FFO" means funds from operations.

before and after the Maui Wildfire. There are several contributing factors for this as discussed below.

B. The Companies' Consolidated ROE Has Been Below Authorized Levels During the Current MRP.

The existing PBR Framework has provided a level of stability and predictability, but it has not sufficiently allowed the Companies to earn their allowed ROEs. As discussed in the Companies Rebasing Brief,[11] the Companies' consolidated ROE has been <u>below authorized</u> during the current MRP.

Consolidated Ratemaking ROE				
	2021	2022	2023	2024[12]
Actual ROE	8.82%	9.05%	8.44%	8.01%
Authorized ROE	9.50%	9.50%	9.50%	9.50%
(Deficiency) between Actual and Authorized	(0.68%)	(0.45%)	(1.06%)	(1.49%)

The gap between the actual ratemaking and authorized ROE represents a revenue deficiency, indicating the need to rebase revenues and rates to allow the utility the opportunity to earn a fair return on its investment in utility property.

C. Target Revenues Derived from the MRP1 I-Factor Were Not Sufficient to Keep Up with Actual Inflation During MRP1.

Revenues under the current Annual Revenue Adjustment ("ARA") have been insufficient in light of cost increases far above the I-Factor (*i.e.*, the forecasted gross domestic product price index ("GDPPI")) and the Companies' need to make significant expenditures and capital investments in public safety and other necessary utility purposes.

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[11] Hawaiian Electric Companies' Brief on the Rebasing of Target Revenues ("Rebasing Brief") filed on December 5, 2024, in Docket No. 2018-0088.

[12] 2024 ratemaking ROE was adjusted to exclude the impact of the settlement of wildfire tort claims and the asset-based lending facility intercompany costs.

The Companies conducted an analysis[13] to evaluate if target revenues derived from an I-Factor were sufficient to keep up with actual inflations during MRP1 (June 1, 2021 – May 31, 2026) as described in Decision and Order No. 37507 ("D&O 37507") in Docket No. 2018-0088:[14]

> [T]he PBR Framework established a multi-year rate period ("MRP") of five years, during which Hawaiian Electric's annual target revenues will be primarily derived from the application of a formula consisting of the following factors: (1) **an inflation factor ("I-Factor"), to allow revenues to keep pace with inflation**; (2) a pre-determined annual productivity factor ("X-Factor"); (3) an exogenous events factor to allow the Companies to seek cost recovery for events outside of Hawaiian Electric's control that result in a severe impact ("Z-Factor"); and (4) a stretch factor intended to share with customers the benefits and cost savings expected to accrue to the utility under the PBR Framework ("Customer Dividend" or "CD"). Collectively, these four factors comprise the Annual Revenue Adjustment mechanism ("ARA") which will provide for annual adjustments to Hawaiian Electric's target revenue during the MRP.

The Companies compared the compounded portion of the ARA for MRP1 calculated using: (i) forecasted annual percentage change from prior year in GDPPI for the I-Factor; and (ii) actual GDPPI for the I-Factor. The analysis of the revenue (deficiency)/surplus, including and excluding revenue taxes, shows that the compounded portions of the ARA (I-Factor, X-Factor, Multiplicative CD-Factor, and prior years' compounded portions of the ARA) calculated using the forecasted GDPPI in the approved 2021 Annual Decoupling filing and 2021-2023 Fall Revenue Reports were not sufficient to keep pace with the actual GDPPI over that same period. Because the forecasted GDPPI used in the ARA calculation for Year 1 and Year 2 of MRP1 (*i.e.*, 2021 and 2022) was significantly lower than the actual GDPPI for those years, the deficiencies in revenues derived from an I-Factor for those years have been

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[13] *See* Exhibit 1 to this brief.
[14] D&O 37507 at 30-31 (emphasis added).

compounded in the ARA calculation. Through the end of December 2024, the cumulative revenue deficiency derived from the I-Factor and the resulting impact of the customer dividend amounted to $233.1 million, including revenue taxes, for the consolidated Companies (Hawaiian Electric: $156.9 million, Hawai‘i Electric Light: $38.5 million, Maui Electric: $37.7 million). The cumulative revenue deficiency, including revenue taxes, is estimated at $384.9 million (Hawaiian Electric: $259.0 million, Hawai‘i Electric Light: $63.6 million, Maui Electric: $62.2 million) through May 2026 (the end of MRP1), assuming the GDPPI of 2.2% for 2025 and 2.0% for 2026.

D. EPRM Has Not Provided Recovery for Large, Spiky Investments as the Companies Believe Was Originally Contemplated.

One reason the Commission set the X-Factor at zero was the intent that a case-by-case review of large capital projects via the Exceptional Project Recovery Mechanism (“EPRM”) was a better and more practical means to address those investments rather than by including a fixed X-Factor revenue adjustment to account for them. In the PBR proceeding, the Commission staff observed that “lumpy” investments cannot feasibly be addressed by an externally-indexed annual revenue adjustment mechanism.[15] However, the then existing MPIR mechanism (predecessor to the EPRM) excluded business as usual projects from MPIR recovery, no matter how high the costs of these projects.

The exclusion of business as usual projects originated as a provision of a proposed modification to the REIP mechanism, negotiated and jointly submitted by the Companies and the

[15] The Commission’s *Staff Proposal for Updated Performance-Based Regulations* issued on February 7, 2019 in Docket No. 2018-0088 stated the following: “The Staff Framework includes continuation of the MPIR mechanism, recognizing the need to provide timely cost recovery for necessary, specifically approved major project investments. These “lumpy” investments cannot feasibly be addressed by an externally-indexed ARM formula designed to determine changes in total revenues over many years of an MRP control period. Nor can large project capital expenditures be feasibly predicted for extended future periods.”

Consumer Advocate in the decoupling reexamination proceeding.[16] The Commission did not approve the modifications to the REIP but incorporated many of the proposed modifications to develop the MPIR Guidelines.[17] There was never any stated justification for this exclusion and why business as usual projects should not have a mechanism for recovery. In fact, the Commission recognized the need for the Companies to be able to recover the costs of major projects between rate cases. In Order No. 32735, issued on March 31, 2015 in the decoupling reexamination proceeding, the Commission established a RAM Cap and other changes that were "designed to provide the commission with control of and prior regulatory review over substantial additions to baseline projects between rate cases"[18] but stated that the Companies may still apply for recovery of "**any type** of Major Project (including related baseline projects considered on a programmatic basis as Major Projects), to be implemented through the RAM, REIP or other proposed mechanism if found to be reasonable and prudent."[19] The Commission further stated that its order "<u>does not deprive the HECO Companies of the opportunity to recover any prudently incurred expenditures or limit orderly recovery for necessary expanded capital programs</u>" [emphasis added] but rather that it "limits the amount of unapproved capital project expenditures that can automatically be incorporated into effective rates through the RAM without timely prior regulatory review."[20]

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[16] *Joint Proposed Modified REIP Framework/Standards and Guidelines*, filed on June 15, 2015 in Docket No. 2013-0141, Exhibit 1 at 8.
[17] Order No. 34514, Docket No. 2013-0141, at 101.
[18] Order No. 32735, Docket No. 2013-0141, at 7.
[19] Order No. 32735, Docket No. 2013-0141, at 89 (emphasis added). "Major Project" means a resource plant addition subject to application and review in accordance with the applicable provisions of the Commission's General Order No. 7. D&O 37507, Docket No. 2018-0088, Appendix A at 2. "REIP" refers to the Renewable Energy Infrastructure Program adjustment mechanism approved in the Decision and Order issued on December 30, 2009 in Docket No. 2007-0416.
[20] Order No. 32735, Docket No. 2013-0141, at 7.

In Order No. 34514, which established the MPIR mechanism, the Commission stated: "…accordingly, recovery of revenues for costs of Major Projects placed in service between general rate cases will be through the MPIR adjustment mechanism" but also that "the HECO Companies may request interim recovery of revenues for projects that are not Eligible Projects as defined in the Guidelines through other means, including, for qualifying projects, the REIP."[21]

In Phase 2 of the PBR proceeding, the Companies recommended that there should be clarification that major projects for 1) equipment or facilities for new developments or unserved areas or to serve growth in an area, 2) resiliency, 3) energy storage and 4) the repowering or replacement of existing power plants should be eligible for MPIR recovery since these types of projects arguably are not business as usual projects. The Companies also proposed an alternative for the EPRM to have two tiers, the first would include transformative projects with the existing $2.5 million threshold and the second would include all other projects with costs of $30 million or more.[22] This would better address the difficulty of designing an index-based ARA to adequately recover "lumpy" investments as the Commission staff had pointed out initially and eliminate the need to determine whether a particular project was business as usual or not.[23]

In D&O 37507, the Commission decided to limit eligibility to "exceptional" projects as determined on a case-by-case basis rather than provide further clarification on what types of projects would be eligible.[24]

However, after the issuance of D&O 37507 in which the X-Factor was set at zero, the Commission subsequently found that the Kulanihakoi Substation project, a project that would

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[21] Order No. 34514, Docket No. 2013-0141, at 105-106 (emphasis added). *See also* Order No. 34514 at 120-121.
[22] *See* the Companies' response and supplemental response to PUC-Parties-IR-04, subpart a. filed on September 15, 2020 and September 17, 2020, respectively, in Docket No. 2018-0088.
[23] *Post-Hearing Brief of the Hawaiian Electric Companies*, filed on October 19, 2020, Docket No. 2018-0088, at 19-20.
[24] *See* D&O 37507 at 83-86.

serve new load growth, constitutes a business-as-usual investment and would be ineligible for EPRM recovery.[25]

Decision and Order No. 38451 for the Kahe-Waiau 138 kV Undergrounding Project in Docket No. 2021-0086 (at 64-66) then ruled that not only must a project meet the eligibility requirements set forth in the EPRM Guidelines to be eligible for EPRM recovery, but it must also be found to be "exceptional" even though there was no express definition of "exceptional" in the EPRM Guidelines or elsewhere. This was the first time a two-step eligibility process had been ordered and the Companies up to that point had interpreted "exceptional" to only mean that the project satisfied the eligibility requirements in the EPRM Guidelines.

Order No. 38279, which clarified Decision and Order No. 38084 for the Waena Switchyard/Synchronous Condenser Project in Docket No. 2020-0167, ruled that "the overhead costs that may be recovered through the EPRM are costs that are tracked and can be demonstrated to result from implementation of the Project and would not be incurred without implementation of the Project" and that "overheads and on-costs that represent costs that are not incurred by the Company as a direct result of the Project shall be excluded [from EPRM recovery]."[26] This effectively eliminated the recovery of fixed overheads allocated to EPRM projects even though such recovery had been allowed in previous MPIR dockets and as the Companies asserted, the overheads allocated to these specific projects were not included in revenue requirements in previous rate cases and therefore were not recovered in base rates.[27]

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[25] *See* Decision and Order No. 38094, Docket No. 2020-0182, at 64. Order No. 38127, Docket No. 2020-0182, at 1, stated that eligibility for cost recovery under the EPRM is determined by the nature of the project and not the magnitude of its costs (in this case $16 million).

[26] Order No. 38279 issued on March 17, 2022, in Docket No. 2020-0167 at 17 (footnotes omitted).

[27] *See Maui Electric Company, Limited's Motion for Partial Reconsideration and/or Clarification and Partial Stay of Decision and Order No. 38084*, filed on December 3, 2021, Docket No. 2020-0167, at 4-13. Also, *Hawaiian Electric Company, Inc.'s Motion for Partial Reconsideration and Clarification of Order No. 38197*, filed on February 7, 2022, Docket No. 2021-0017, at 4-15.

These orders raised new requirements and effectively narrowed the scope of recovery of capital projects after the issuance of the PBR Phase 2 D&O 37507. Thus, there was no mechanism in MRP1 to account for large "spikey" business-as-usual capital investments, which by acknowledgement are not well-suited for fixed formula-based recovery and there was uncertainty whether projects that satisfied the eligibility criteria in the EPRM Guidelines would also be found to be "exceptional" and therefore recoverable under the EPRM. The Companies' inability to recover large and necessary investment projects like the Kulanihakoi Substation means recovery must be had under the fixed ARA, which further means that other projects cannot be funded, or, as was the case, the ARA revenues were insufficient to allow recovery for capital projects the Companies placed into service (essentially on the shareholders' tab).

E. PIM Revenues Have Been Significantly Below Anticipated Levels.

ARA revenues should be sufficient to allow the Companies, through efficient management, to earn their authorized ROE. Performance incentive mechanisms ("PIMs") should modulate earnings above or below ROE based on Company performance measured against established targets. PIM rewards should not be necessary to fund core business-as-usual work.[28] But with shortcomings of the ARA, earning PIM rewards became necessary to fund core work. Unfortunately, through design issues for some PIMs, and an unrealized promise of higher reward opportunities (the 150-200 basis point reward originally contemplated when the MRP1 PIM structure was designed),[29] the Companies PIM earnings have been relatively meager and,

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[28] In previously addressing "Additional Revenue Opportunities" for the Companies, the Commission stated that "PIMs and SSMs play a critical role in the PBR Framework" as they "represent additional opportunities for the Companies to earn revenues and improve their financial position" and are "intended to act in a complementary fashion by balancing the cost control incentives delivered through the ARA with opportunities to earn significant financial rewards for exemplary performance." *See* D&O 37507 at 91-92.

[29] D&O 37507 at 94, footnote 164 states "Accordingly, while the Phase 1 Staff Proposal had indicated a potential PIM Portfolio of approximately 150-200 basis points, see Phase 1 Staff Proposal at 34, the value of the initial portfolio approved in this D&O is more conservative, to provide 'room' to accommodate future PIMs and/or SSMs that may be developed in the Post-D&O Working Group and/or in other proceedings."

for all MRP1 years except 2024, the Companies have paid more in penalties than they have earned in rewards.

The table below provides potential maximum and actual rewards and penalties of incentive mechanisms for the performance evaluation years 2021-2024. The rewards and penalties are expressed as the impact on the Companies' return on equity in basis points ("bps").

<u>Hawaiian Electric Companies (Consolidated)</u>
<u>Max Potential and Actual PIM Reward/ (Penalty)</u>

		Max Potential Reward				**Max Potential (Penalty)**				**Actual Reward/ (Penalty)**			
		Basis Points at Max Potential Reward				Basis Points at Max Potential Penalty				Basis Points at Actual			
Incentive Mechanism	Type	2021	2022	2023	2024	2021	2022	2023	2024	2021	2022	2023	2024
T&D SAIFI	Penalty	0	0	0	0	(11)	(11)	(10)	(5)	0	0	(2)	0
T&D SAIDI	Penalty	0	0	0	0	(11)	(11)	(10)	(5)	(1)	(0)	(10)	(3)
Call Center Performance	Reward/Penalty	4	4	4	4	(4)	(4)	(4)	(4)	0	0	0	0
RPS-A	Reward	3	13	9	12	0	0	0	0	3	0	1	6
Grid Service	Reward	5	5	5	0	0	0	0	0	0	0	3	0
Interconnection Approval	Reward/Penalty	10	10	9	9	(3)	(3)	(3)	(3)	9	10	9	7
AMI Utilization	Reward	7	6	6	0	0	0	0	0	0	0	0	0
LMI Energy Efficiency	Reward	0	6	6	6	0	0	0	0	0	1	0	0
Generation SAIFI	Penalty	0	0	0	0	0	0	(2)	(2)	0	0	0	0
Generation SAIDI	Penalty	0	0	0	0	0	0	(2)	(2)	0	0	0	(0)
Interconnection of Utility Scale Renewable Projects	Reward/Penalty	0	0	0	0	0	0	0	0	0	0	0	0
Collective Shared Savings Mechanism	Reward	0	0	0	0	0	0	0	0	0	0	0	9
Sub-Total PBR PIMs		**28**	**44**	**39**	**31**	**(30)**	**(29)**	**(29)**	**(21)**	**12**	**11**	**2**	**18**
Phase 1 Renewable Energy PIM/SSM	Reward	21	11	4	3	0	0	0	0	0	0	0	1
Phase 2 Renewable Energy PIM/SSM	Reward	0	0	0	0	0	0	0	0	0	0	0	0
EV-Maui SSM	Reward	0	0	0	0	0	0	0	0	0	0	0	(0)
ECRC Heat Rate Mechanism	Reward/Penalty	0	0	0	0	0	0	0	0	(17)	(12)	(17)	(18)
ECRC Risk Sharing	Reward/Penalty	12	12	11	11	(12)	(12)	(11)	(11)	(12)	(12)	8	6
Sub-Total Non PBR PIMs		**34**	**23**	**15**	**14**	**(12)**	**(12)**	**(11)**	**(11)**	**(28)**	**(24)**	**(8)**	**(11)**
Total PIMs		**62**	**68**	**54**	**45**	**(42)**	**(41)**	**(41)**	**(32)**	**(16)**	**(13)**	**(6)**	**7**

In terms of design and targets, certain PIMs have not provided meaningful or valuable incentives. For example, rewards under the RPS-A PIM have not approached previously stated potentials, largely because of numerous factors outside of the Companies' control during and after the pandemic. The target performance for the AMI Utilization PIM was unreasonably difficult to achieve and therefore was not a meaningful incentive. With respect to the LMI Energy Efficiency PIM, it was difficult for the Companies to determine what performance was required to earn a reward (*i.e.*, to exceed Hawai'i Energy's targets) during the actual performance period. On the other hand, the Interconnection Approval PIM has been a successful motivational tool because, as designed, the means of performance are largely under the Companies' control and the targets were based on an existing baseline of performance. Thus the Companies performed well on this desired outcome and earned meaningful rewards. The same was true, at least for one year, for the Grid Services (acquisition) PIM.

II. How Hawaiian Electric's Performance Has Matched Up with the PBR Framework's Goals and Outcomes.

In developing the PBR Framework for MRP1, the Commission first adopted twelve priority outcomes that were intended to be advanced by incentives. The following provides the Companies' evaluation of how their performance has matched up with the PBR Framework's Goals and Outcomes, whether any new goals or outcomes should be considered for MRP2, and which mechanisms the Companies propose to be examined during Phase 6 for potential modification.

A. Affordability

Under the existing PBR Framework, the Companies currently track Affordability through the following reported metrics: (1) Low-to-Moderate Income ("LMI") Energy Burden Reported Metric; (2) Payment Arrangement Reported Metric; and (3) Disconnections Reported Metric. The metrics are described and defined on the Hawaiian Electric website.[30]

During MRP1, as measured by the LMI Energy Burden metric, energy cost as a share of income increased in 2022 across all islands, likely due to the Russia-Ukraine conflict and supply chain delays causing spikes in fuel prices. LMI households on Hawai'i island and Lana'i experienced the greatest bill increases in 2022, with energy burdens gradually decreasing in 2023 and 2024 despite continued international conflict. Energy burdens across all service territories

[30] *See* https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/affordability.

have since reduced nearly to their 2021 levels. Since 2023, the Companies have routinely shared updated utility assistance options lists, including those from the Hawaiʻi Home Energy Assistance Program, Catholic Charities, and Salvation Army on their Payment Arrangement website, which may have contributed to the recent decrease in energy burden.

Payment arrangements remained steady in 2021-2022, supported by the COVID-19 disconnection moratorium in place through May 2021. A phased-in approach in disconnections then resumed, beginning with the largest and oldest arrearage balances, resulting in a relatively flat volume of customers and payment arrangement. In 2023, however, the continuation of the targeted disconnection effort, combined with a lowered arrearage balance threshold, led to a sharp increase in payment arrangements across all service territories. Residential customers accounted for the highest number of new arrangements and as customers with smaller arrears balances received disconnection notices, many took advantage of longer-term special payment arrangements up to 24 months, further driving the increase in sign-ups.

The disconnection moratorium implemented during the COVID-19 pandemic beginning March 2020 through May 2021, along with the Companies phased-in approach for disconnections subsequent to the moratorium resulted in relatively few disconnections at the beginning of MRP1 for all service territories. As noted above, with the phased-in approach for disconnections and the gradual lowering over time of the arrearage threshold for disconnections, with the exception of Maui, the number of disconnections began to rise in 2022 and continued to increase as the Companies worked toward returning to pre-pandemic collections levels. Following the Maui wildfires, Acting Governor Sylvia Luke issued an emergency proclamation executive order that authorized and invoked certain emergency provisions to address the Maui wildfires. On August 31, 2023, the Commission issued Order No. 40218 directing Maui utilities to suspend termination or disconnection of regulated utility services due to non-payment. Order No. 40313 ordered that the suspension period would continue though the effective date of the Governor's emergency proclamations relating to Maui wildfires. Governor Josh Green's latest proclamation extended the disaster emergency relief period through June 3, 2025.

Since the COVID-19 moratorium on disconnections, the Companies have offered customers special payment arrangements up to 24 months, which has gradually been reduced to their current 4-month installment period and longer terms based on customer need. The Companies also offer multiple forms of assistance and resources including special payment arrangements, vulnerable customer programs like the Special Medical Needs Program, financial assistance referrals to the Hawai‘i Home Energy Assistance Program, government assistance subsidies, and educational opportunities and referrals to Hawai‘i Energy to customers struggling to pay their energy bills. The Companies also ensure vulnerable customers are protected from automatic disconnections if the customers are enrolled in the Special Medical Needs Program, are on life support, and/or receive other critical care services. Customers are encouraged to contact the Companies for assistance and referrals to reduce their likelihood of disconnection.

It is fair to suggest that, in MRP1, due to impacts from the pandemic, the Maui Wildfires and multiple extended disconnection moratoriums, it is somewhat difficult to judge the impact of PBR on the payment arrangement and disconnection metrics.

Looking forward, the Companies will propose to modify or supplement the Affordability metrics to better reflect household energy burden, which is a recognized standard for measuring energy affordability. Energy burden is generally defined as the percentage of a household's income spent to cover energy cost.

Energy burden is an important factor in discussion and evaluation of energy equity and affordability, and meaningful localized knowledge can lead to the application and modification of energy burden metrics. It considers energy in the context of all household expenses.

Because Hawai‘i has the second most persons per household, energy burden metrics per person can be considered a refinement of the energy per household metric. The evolution toward electrification of transportation shifting transportation fuel energy use and cost into the home electricity use and costs should also be considered when evaluating household energy costs. A household energy burden metric would provide a more comprehensive and accurate measurement of affordability due to these unique factors in Hawai‘i.

B. Reliability

The Companies' performance under the reliability priority outcome, as measured by reliability indices, demonstrated a generally improving trend from 2018 through 2022. With the exception of SAIFI for Hawai‘i Electric Light in 2022, SAIDI and SAIFI exhibited overall improvement during this period compared to 2018. However, data for 2023 and 2024 indicates a significant worsening in both SAIDI and SAIFI. This increase is largely attributed to the implementation of enhanced wildfire mitigation measures, which included more sensitive protective relay settings and the temporary disabling of automatic reclosing operations. As shown on the Companies' Performance Scorecards and Metrics website,[31] since the T&D SAIDI and T&D SAIFI PIMs first took effect in 2018,[32] the Companies' reliability performance for all systems (sum of T&D and Generation) was as follows:

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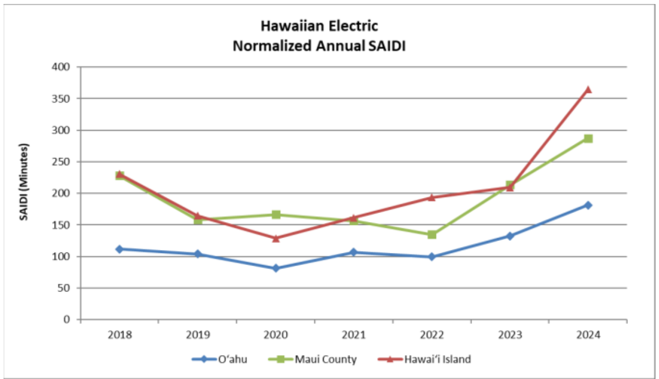
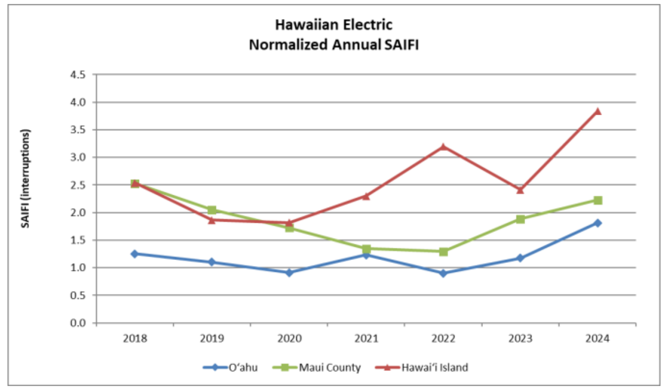
[31] Source: https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/service-reliability. System Average Interruption Duration Index and System Average Interruption Frequency Index historical data.
[32] In Order No. 34514 in Docket No. 2013-0141 issued on April 27, 2017, the Commission, among other things, established the T&D SAIDI and T&D SAIFI PIMs. In Order No. 35165 in Docket No. 2013-0141 issued on December 29, 2017, the Commission ordered the Hawaiian Electric Companies to file PIM and revised RBA tariff sheets to become effective January 1, 2018.





Historically, the Companies have strategically invested in sectionalizing technologies, including fuses, smart fuses, and reclosers, to limit the number of customers impacted by faults. Furthermore, the deployment of reclosers and advanced protective schemes, such as fuse saving, has augmented system restoration capabilities. The observed improvement in reliability indices from 2018 to 2022 underscores the historical effectiveness of these sectionalizing and reclosing strategies. The impact of the recent wildfire protection protocols, which temporarily constrained these operational functionalities, highlights the substantial contribution of sectionalizing and reclosing to overall system reliability.

The Consumer Advocate has also previously observed:

> The Consumer Advocate observes that during previous spring reviews, the Company reported minimal penalties for the T&D Reliability PIMs. For instance, during the 2023 spring review, performance targets were missed by HELCO which resulted in a T&D SAIDI PIM penalty of $78,821; however, performance levels in all other service territories were within parameters (or deadbands) established under the PBR Framework resulting in no other T&D Reliability PIM penalties for the Company. Similarly, during the 2022 spring review, performance targets were missed by MECO which resulted in a T&D SAIDI PIM penalty of $181,520; however, performance levels in all other service territories were within parameters (or deadbands) established under the PBR Framework resulting in no other T&D Reliability PIM for the Company. Unlike previous years, as mentioned above, each of the Company's service territories performance levels exceeded the parameters established under the PBR Framework resulting in T&D SAIDI PIM penalties

> of $2,278,410 for HECO, $547,930 for HELCO, and $310,868 for MECO; and a T&D SAIFI PIM penalty of $585,404 for HELCO.
>
> The Protective Measures put in place since the August 2023 Wildfire appear to have impacted the Company's T&D Reliability PIMs – examples of specific events and field data and analysis regarding the impact of the measures on the PIMs were provided by the Company in its April 2024 Request. Historical information collected and reported by the Company regarding T&D SAIDI and SAIFI measurements, as normalized, demonstrate that these metrics for the 2023 evaluation period to be noticeably higher (worse) in relation to previous years…[33]

C. Interconnection Experience

1. DER Interconnection

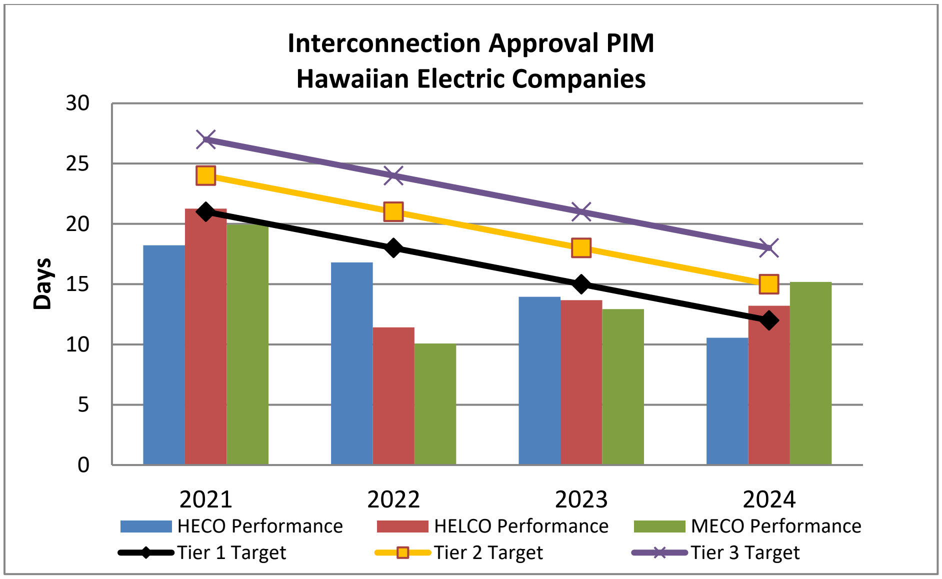
The Companies' Distributed Energy Resource ("DER") interconnection approval performance improved in MRP1.

The Interconnection Approval PIM was established to promote the PBR outcome of Interconnection Experience by incenting the Companies to reduce the time necessary to complete those steps within the Companies' control to interconnect DER systems <100 kW in size.[34] In setting the reward targets for this PIM, the Commission stated: "These targets are designed to incent incremental improvement on existing interconnection approval times, working backwards from a desired end-state that reflects national exemplary performance."[35] More specifically, the Commission clarified that the reward targets "were developed by working backwards from the desired performance at the end of the MRP (which is based on reflecting nation-wide exemplary performance), without being overly aggressive on annual improvements, compared to historical performance and considering improvements over time."[36] Thus, the reward structure was

[33] Division of Consumer Advocacy's Statement of Position filed on April 30, 2024 in Non-Docketed Case No. 2023-04666, Transmittal No. 24-01 (Spring Revenue Report) at 19-20 (footnotes omitted).
[34] D&O 37507 at 95-99, and 214.
[35] *Id.* at 96.
[36] *Id.* at 102.

established as a tiered system to incentivize the Companies to achieve incremental efficiencies over time.

Given the background on the PIM's objectives described above, in the Companies' view, the Interconnection Approval PIM has achieved its intended objectives based on the Companies' performance during MRP1, which is summarized below:[37]



Notably, the Companies achieved Tier 1 for all three Companies in 2022 and 2023. Maui and Hawai‘i Island saw an almost 50% reduction in average interconnection times between 2021 and 2022. On O‘ahu, which experiences the highest volume of applications, average interconnection times were consistently decreased year-over-year, resulting in a 42% reduction from 2021 to 2024. Overall, this has enabled customers to more immediately energize their systems and realize the benefits of their rooftop solar and/or energy storage systems. This outcome improves the customer's interconnection experience and achieves the Commission's stated objectives of the PIM.

[37] The Companies' Interconnection Approval PIM performance for the 2021 to 2024 evaluation periods is discussed in the "Annual PIM and SSM Performance Review" section of the February Notice Transmittals filed in Transmittal Nos. 22-01, 23-01, 24-01, and 25-02.

As explained in detail in the Companies' 2023 Notice Transmittal,[38] and in response to PUC-HECO-IR-102, part b,[39] the Companies were able to achieve these performance targets due to multiple ongoing process improvements over, in particular, the first two years of the PIM, in addition to ongoing process improvements that they already initiated prior to the start of the PIM. In 2021, the Companies initiated a Lean Six Sigma methodology to assess, prioritize, and initiate new process improvements in direct response to this PIM, with a focus on Hawaiian Electric, and implemented selected improvements in 2022. Specific process improvements discussed in the Companies' 2023 Notice Transmittal included the following initiatives: 1) Residential Time-of-Use Processing Transition; 2) Removal of Customer Energy Resources ("CER") Ownership Change Forms; 3) Removal of Certificate of Insurance Annual Renewal Notification; and 4) Meter Replacement Durations Reduction.[40]

Improvements 1, 2, and 3 focused on reallocating or removing non-value-adding administrative effort that resulted in approximately 700 hours per year of CER labor as well as improved customer experience. This improved work prioritization contributed towards approximately a 20% decrease in the Completeness Review component of the PIM for Hawaiian Electric from 2021 to 2022. Improvement item 4 represents a number of process improvements to streamline the meter replacement process. Examples include meter notification training to decrease manual errors, and the development of a customer FAQ brochure for Meter Technicians to decrease service refusals. The cumulative impacts of this improvement effort contributed to a

[38] *See* Hawaiian Electric Companies' Notice Transmittal, filed February 28, 2023, in Transmittal No. 23-01 ("2023 Notice Transmittal").

[39] *See* Hawaiian Electric Companies' Responses to PUC-Parties-IR-18 and PUC-HECO-IRs 102-103, filed on September 20, 2023, in Docket No. 2018-0088.

[40] *See* Companies' 2023 Notice Transmittal at 25-29 for further detail on each of these initiatives and other process and efficiency improvements.

decrease in meter changeouts from an average of 22.6 days (January through May 2022) to 7.3 days (June through December 2022) on O‘ahu.

Prior to the new process improvement efforts that the Companies started in direct response to the PIM, the Companies had already initiated a number of improvement efforts that were ongoing by the time the PIM started. These pre-PIM efforts were started as a means to help customers and the solar contractor industry through the COVID-19 pandemic. These efforts included: 1) early energization; 2) revenue meter changeouts upon conditional approval; 3) activation of contractor meters or socket covers for Grid Supply Plus production meter sockets; and 4) the pre-approval program (Quick Connect) where customers could build first and apply later. The Companies worked on these improvements in collaboration with the solar industry, and they were discussed in detail in the Commission’s investigatory proceeding on DER Policies, Docket No. 2019-0323.[41]

In 2023 and 2024, the Companies continued to focus heavily on implementing process efficiencies and prioritizing resources to reduce interconnection timelines and achieve PIM performance targets across all three service territories. Similar to the 2023 evaluation period, the CER team that receives applications continued to send meter notifications to Meter Shop earlier upon receipt of a CER application rather than at the end of completeness review. This enabled both processes to be done in parallel to speed up the overall time it takes for a customer to be able to energize and enjoy the benefits of their system.

In addition, throughout MRP1, process efficiencies and improvements were realized by leveraging a “One Company” model where CER Coordinators were able to use the Customer Interconnection Tool (“CIT”) and seamlessly process applications independent of service

[41] *See, e.g.*, Hawaiian Electric Companies’ Status Update on COVID-19 Related Process Improvements, filed June 10, 2020, in Docket No. 2019-0323.

territory. For example, after the August 2023 windstorm and wildfires on Maui, Maui CER employees were assigned to the Companies' recovery efforts for several months. Hawaiian Electric employees on O‘ahu processed Maui applications through CIT so that workflows could continue. Finally, resource optimizations and workload prioritization were all contributing factors to the Companies' ability to achieve PIM targets throughout MRP1.

2. Utility Scale Interconnection

During MRP1, the Companies were in the process of interconnecting the RFP Stage 1 and Stage 2 projects. The Companies believe the IPP interconnection process can and should be improved, which requires commitment and cooperation from IPPs as well. For the Companies' part, based on experience gained during the Stage 1 and 2 RFPs, which was the first time the Companies interconnected this magnitude of projects across three islands at the same time, the Companies developed various process improvements for the procurement and interconnection of large renewable projects which were implemented during MRP1 to improve the interconnection experience for independent power producers:

1. Accelerating and streamlining engineering aspects of the interconnection process which could expedite a project's schedule.[42]

[42] Efforts to expedite project schedules have included the following for Company-Owned Interconnection Facilities ("COIF"): (1) standards and specifications being provided to developers earlier in the process, (2) the Companies reviewing a developer's 30% design and up to 60% design for COIF during a new early engineering option provided to developers, (3) Companies preparing up to 60% design for COIF to be built by the Companies during the early engineering phase, (4) providing additional documentation (*e.g.*, "go-bys," seed files, samples of other COIF designs) to aid developers, and (5) reducing the Companies' design review time from 30 days to 25 days. These efforts could allow for the developer to submit permits earlier in the process.

2. Revised sequencing of activities to shorten the Interconnection Requirements Study ("IRS") process to allow for more paralleling of efforts for the System Impact Study ("SIS") and Facility Study ("FS").[43]

In their Stage 3 RFP, the Companies have implemented the following process improvement modifications to expedite the interconnection process:

1. The Companies introduced a new model checkout process into the RFP process designed to mitigate model quality/accuracy issues in the SIS phase. This was intended to improve the quality of models received at the start of IRS by providing Proposers feedback earlier. Previously, the Companies waited until project selection to review models.[44]

2. The Companies provided developers with preliminary interconnection requirements in order to reduce overall cost risk to developers.[45]

3. The Companies provided developers with transmission capacity information early in the process so that they have a better sense of issues that may exist with proposed points of interconnection.[46]

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[43] Examples of efforts to expedite the process include: (1) completion of a preliminary FS prior to completion of the SIS (a Final FS is updated based on results of the SIS) which allows for developers to receive information provided by the FS in a more timely manner; and (2) providing single line diagrams prior to completion of the SIS in order to begin the Final FS earlier.

[44] For the Stage 3 RFP process, the Companies performed (1) a threshold requirement that a bidder provides models and model documentation as proof that models were self-tested and work as expected, (2) a non-price evaluation category that grades the quality and acceptability of the models, (3) a detailed evaluation phase where the model is checked, at the developer's cost, to identify any model deficiencies, and (4) as part of the post-selection process, require that a revised, working model be provided within 30 days of selection. The Companies anticipated that this would help to ensure that working models were ready to begin the IRS 30 days after selection, which would significantly reduce the amount of time between selection and completion of the IRS.

[45] The Companies provided developers with pre-identified remote substation requirements typically found in the FS part of the IRS. Based on potential transmission lines or substations, the Companies provided known requirements upon issuance of an RFP so developers would have better informed bids. The requirements would be confirmed in the IRS process.

[46] A system study determines the available MW capacity in transmission lines and substations that are available to interconnect. This mitigates the risk that transmission line upgrades will be needed as part of a proposed project, reducing cost and time to complete interconnection.

4. The Companies proposed to complete the IRS prior to execution of a power purchase agreement ("PPA"). The intent was to make it more likely that PPA milestones match the results of the IRS and that this would incentivize both the developer and the Companies to move through the IRS process quickly.[47] As contemplated in the PIM, the IRS would be completed within 10 months of receiving working models. However, the start of the IRS was delayed due to the late receipt of working models from developers. Additionally, during the IRS, certain developers were late with additional deliverables, which delayed their respective Facility Studies. Without commitment from the developers to submit working models, and required deliverables timely, this process improvement did not result in the intended benefits.

In their IGP RFP, the Companies are proposing the following process improvements to further expedite the interconnection process:

1. Taking a step further to provide more preliminary interconnection information tailored to each proposal with the introduction of a new process to provide a Preliminary Interconnection Report ("PIR"). A PIR Meeting will also be scheduled as part of the process to improve the likelihood that Proposals include an accurate assessment of necessary interconnection costs for their proposed interconnection points.
2. Requiring direct conversations between developers' engineering and OEM consultants and the Companies' consultants during the model validation stage.
3. Requiring developers to participate in early engineering for COIF to further expedite the engineering process.

[47] In Stage 1 and Stage 2, PPA negotiations and the IRS were bifurcated, with the IRS being completed after the PPA was executed. Bifurcation was done to allow portions of the project to move forward while the IRS was completed in an effort to streamline the process. The Companies have seen significant improvements in IRS completion times between Stage 1 and Stage 2.

In addition, going forward, the Companies support continuing to have an independent engineer ("IE") for future procurements. The Companies' IE concept includes the following proposed elements: (1) the IE would report to the independent observer ("IO") so that there is one overall authority; (2) the IE would be hired by the Commission, (3) the IE would report to the Commission through the IO; (4) the IE would be part of the interconnection discussions and review of interconnection documents between the Companies and the developers; (5) the IE would review the Companies' requirements and standards for interconnection; and (6) the IE must have certain experience and qualifications, such as experience with island grids and interconnecting projects.

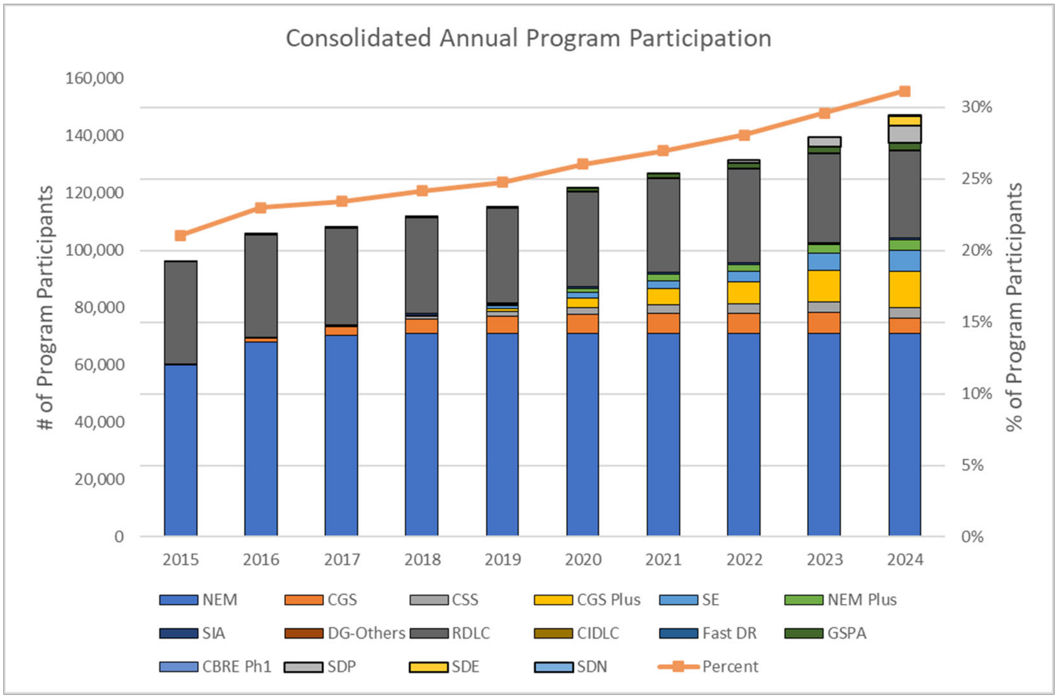
D. Customer Engagement

The Customer Engagement metrics are described on the Companies' website.[48] Among other metrics, the Program Participation Scorecard tracks the number and percent of customers that are enrolled in the Hawaiian Electric's Community-Based Renewable Energy ("CBRE"), DER, and Demand Response ("DR") programs, compared to a target of 30% of the total number of customers.

From 2021 to 2024, the Companies increased customer engagement in CER programs by 20,345 participants in both DER and DR programs, nearing the 30% target:[49]

48 *See* https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/customer-engagement.

49 Source: https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/customer-engagement Program Participation Scorecard historical data. The graph additionally includes Scheduled Dispatch Program ("SDP"), Smart DER Export ("SDE"), Smart DER Non-Export ("SDN").



During this time period, multiple changes were made to the Companies' CER programs. The Scheduled Dispatch Program ("SDP") or "Battery Bonus" program was launched to drive customer investment in new batteries on O'ahu in 2021, and later on Maui in 2022. The Battery Bonus program was closed to new participants as of July 1, 2024 on Maui and January 1, 2024 on O'ahu, after acquiring 6.36 MW and 33.34 MW of enrolled capacity, respectively. On April 1, 2024, Hawaiian Electric launched the Smart DER Export ("SDE"), Smart DER Non-Export ("SDN"), and the Bring Your Own Device ("BYOD") Level 1 programs.[50] On March 29, 2024, several interim CER programs closed to new customers – Customer Grid Supply Plus ("CGS Plus"), Customer Self-Supply ("CSS"), Smart Export ("SE"), and Standard Interconnection Agreement ("SIA"). The purpose for these changes was for SDE, SDN, and BYOD Level 1 to serve as the long-term CER programs going forward, and to transition customers from interim programs into the long-term programs to streamline programmatic

[50] There were no executed BYOD Level 1 enrollments until February 2025. Therefore, BYOD Level 1 is not reflected in the chart above.

offerings. Most recently, due to low enrollment in BYOD Level 1, the Commission ordered the Companies to launch the BYOD Plus program on May 15, 2025. The Companies are currently planning on timely launching BYOD Plus and will continue Marketing Education & Outreach efforts on available CER programs to increase enrollment in CER programs and overall customer engagement consistent with this metric.

Participation in CBRE has not materialized as all had hoped. Thus, the Companies have stated they will propose in 2025 material changes to the program to make it more probable of reaching its potential.

Although customers are accessing the My Energy Use online portal, the Green Button scorecards show minimal participation. This may be due to its technical nature and use. During MRP1, the Green Button Download My Data Scorecard shows a gradual increase in customers who participated in Green Button Download My Data program from 50 customers in 2021 to 27,779 customers in 2024. Typically, these customers are likely to be more technically equipped to analyze the detailed data on their own. Regarding the Green Button Connect My Data program, the Companies partnered with Hawai‘i Energy to successfully test the third-party vendor registration process for Green Button Connect My Data. While the detailed registration process is published on the Companies' website,[51] the Companies and Hawai‘i Energy emailed 200+ solar and energy efficiency contractors to raise awareness and invited them to participate in a webinar to learn more about Green Button Connect My Data and the registration process, which about 25 contractors attended. To date none of the solar or energy efficiency contractors have registered to become a Green Button Connect My Data partner.

[51] *See* https://www.hawaiianelectric.com/documents/products_and_services/customer_incentive_programs/green_button_connect_instructions.pdf.

During MRP1, the TOU Participation Scorecard shows a significant increase in O‘ahu and Hawai‘i Island TOU customers in the first quarter of 2024 because of the commencement of the Advanced Rate Design TOU Pilot study which assigned customers to TOU rates. For Maui County, where Maui Island customers were exempted from the TOU Pilot study and where Lana‘i and Moloka‘i island customers were not part of the TOU Pilot study, there was a much smaller increase in TOU customers, which reflected customers who elected to enroll in the TOU rates (customers not assigned to TOU rates in the TOU Pilot study, including O‘ahu and Hawai‘i Island customers, could voluntarily elect to be billed on the TOU Pilot rates).

E. Cost Control

The ARA is designed to provide an incentive for cost control. The current ARA formula determines an annual revenue adjustment equal to current target revenues multiplied by the projected rate of inflation (*i.e.*, the gross domestic product price index or "GDPPI") less customer dividends. Because the ARA is decoupled from the underlying cost of service and allows the Companies to retain revenues in excess of costs during the MRP, there is an incentive for the Companies to reduce costs to increase their returns on invested capital. At the same time, the Companies have an obligation to incur expenses and invest in infrastructure necessary to provide safe and reliable service to their customers. This can mask the Companies' efforts to reduce costs and become more efficient. However, during the MRP, although there were cost increases due to inflation in excess of the projected GDPPI and new challenges such as wildfires and pandemics, the ARA effectively shielded customers from much of the impacts of such increases since the ARA revenues were based on the projected GDPPI less customer dividends and not on the underlying cost of service.

During the current MRP, the data shows that the Companies' rate base overall has increased nominally at less than the rate of the actual GDPPI and actually decreased from 2023 to 2024. The table below shows the rate base of each Company[52] and the consolidated rate base for all Companies combined and compares the annual percent change against the actual GDPPI for the period 2020-2024.

Rate Base					
	2020	2021	2022	2023	2024
Hawaiian Electric	$ 2,474,127,000	$ 2,545,697,000	$ 2,681,029,000	$ 2,696,175,000	$ 2,634,847,000
Hawaiʻi Electric Light	$ 515,799,000	$ 546,439,000	$ 570,792,000	$ 634,946,000	$ 657,242,000
Maui Electric	$ 553,196,000	$ 566,841,000	$ 578,655,000	$ 579,274,000	$ 579,686,000
Consolidated	$ 3,543,122,000	$ 3,658,977,000	$ 3,830,476,000	$ 3,910,395,000	$ 3,871,775,000
Percent Change		3.27%	4.69%	2.09%	-0.99%
Actual GDPPI		4.50%	7.10%	3.60%	2.40%

Similarly, net plant additions[53] during the current MRP period (2021-2024) remained relatively flat for the three Companies as shown in the table below.[54]

Net Plant Additions (millions)	2020	2021	2022	2023	2024
Hawaiian Electric	$ 234.3	$ 184.9	$ 197.3	$ 238.3	$ 171.2
Hawaii Electric Light	$ 48.8	$ 48.6	$ 44.8	$ 48.4	$ 55.4
Maui Electric	$ 42.1	$ 60.2	$ 51.1	$ 94.3	$ 76.2
Consolidated	$ 325.2	$ 293.7	$ 293.2	$ 381.0	$ 302.8
Baseline Projects (less than $2.5M)					
Hawaiian Electric	$ 224.5	$ 166.0	$ 174.3	$ 163.6	$ 143.0
Hawaii Electric Light	$ 48.5	$ 41.2	$ 34.8	$ 42.6	$ 48.6
Maui Electric	$ 38.2	$ 53.6	$ 43.9	$ 64.5	$ 74.1
Consolidated	$ 311.2	$ 260.8	$ 253.0	$ 270.7	$ 265.7
Major Projects (greater than $2.5M)					
Hawaiian Electric	$ 9.8	$ 18.9	$ 23.0	$ 74.7	$ 28.2
Hawaii Electric Light	$ 0.3	$ 7.4	$ 10.1	$ 5.8	$ 6.8
Maui Electric	$ 3.9	$ 6.6	$ 7.2	$ 29.8	$ 2.1
Consolidated	$ 14.0	$ 32.9	$ 40.3	$ 110.3	$ 37.1

52 Source: https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/cost-control. Rate Base per Customer historical data.
53 "Net plant additions" are capital expenditures that the Companies record into plant in service when they complete and place into service the associated capital projects. The net plant additions are net of customer contributions.
54 Source: Capital Project Completion Reports for years, 2020-2023, Docket No. 03-0257 and Capital Project Completion Report for 2024, Docket No. 2024-0054.

The exception was 2023. The blip in net plant additions in 2023 was due primarily to implementation of the Grid Mod Phase 1, the Kulanihakoi Substation, the CT1 Turbine Blade Replacement, the Waiau Fuel Oil Tank Farm Containment, the Wahiawa-Waimano 46 kV Relocation, and the Kahe-Waiau 138 kV Undergrounding major projects for Hawaiian Electric and to implementation of the Waena Switchyard and Grid Mod Phase 1 major projects for Maui Electric.[55]

These results appear to be in line with the cost control incentives implicit in the ARA and to address the "capital bias" concerns expressed by certain parties in Phase 1 and 2 of the PBR proceeding. However, capital investment is not inherently undesirable. The Companies must build electrical infrastructure to connect customers to electrical power, to maintain and modernize the electrical grid to provide reliable and resilient electrical service to customers, to protect customers from the impacts of wildfires and other natural disasters and to transmit power from independent power producers and Company-owned generation sources. Thus, there was a need for the Companies to balance the investment in infrastructure against the need to control costs and operate according to the level of revenues allowed through the PBR Framework.

The above tables do not assess the extent to which the PBR Framework provided adequate cost recovery for capital investment. It only compares how capital investment varied compared to the rate of actual inflation and indicates at a high level that the Companies controlled capital investment at less than the rate of actual GDPPI.

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[55] *Capital Projects Completed in 2023*, filed on March 28, 2024, Docket No. 03-0257, Attachment 1 at 10, Attachment 3 at 8.

The experience with O&M expenses during the current MRP was different. The table below shows the percent change in O&M expenses for each Company[56] and the three Companies combined during the current MRP compared to the actual GDPPI and the ARA formula.

O&M Expenses					
	2020	2021	2022	2023	2024
Hawaiian Electric	$ 312,201,304	$ 307,748,413	$ 322,840,813	$ 339,428,623	$ 380,580,281
Maui Electric	$ 88,796,238	$ 82,825,127	$ 85,823,742	$ 104,871,617	$ 121,012,056
Hawaiʻi Electric Light	$ 73,040,981	$ 78,387,911	$ 84,233,298	$ 84,539,872	$ 101,284,439
Consolidated	$ 474,038,523	$ 468,961,451	$ 492,897,853	$ 528,840,112	$ 602,876,776
Percent Change		-1.43%	4.90%	5.14%	12.12%
Actual GDPPI		4.50%	7.10%	3.60%	2.40%
Projected GDPPI in ARA		1.90%	3.00%	3.90%	2.40%
Customer Dividend %		-0.22%	-0.22%	-0.22%	-0.22%
Management Audit Cust Dividend		-0.22%	-0.21%	-0.20%	-0.20%
ARA less Customer Dividend %		1.46%	2.57%	3.48%	1.98%

The table reveals two things. First, the Companies were able to contain O&M expense levels below the rate of actual GDPPI in 2021 and 2022 but found it necessary to incur O&M expenses above the actual GDPPI in years 2023 and 2024. The Companies did indeed implement measures to control their O&M expenses (and in particular, the Companies' financial situation in 2024 required an extraordinary effort to contain costs) but the increase in O&M expense levels to address new priorities and challenges more than offset the impact of these measures. As the Companies explained in the PBR working group meeting on October 25, 2024, the increase in expenses over the current MRP were largely due to wildfire mitigation efforts and increases in insurance premiums, employee medical and health benefits, expanded system operations to support more complex operations with the increase in renewables and wildfire procedures, and cyber risk management to address increases in cyber risk and attacks, among other things.

[56] Source: https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/cost-control. O&M Cost per Customer historical data.

Second, although the ARA provided additional revenues at the projected rate of inflation less customer dividends, the Companies still expended dollars for O&M over this rate to fulfill their public utility obligations, in particular to address the risk of wildfires. The ARA approved by this Commission is based on the projected GDPPI less customer dividends. The customer dividends consist of a -0.22% reduction and a flow through of $6.6 million to the Companies' customers each year to incorporate anticipated benefits due to the management audit findings in the Hawaiian Electric 2020 test year rate case. Exhibit 2 estimates the basis point impact of the annual $6.6 million management audit customer dividend. The above table reflects the projected GDPPI less the percent customer dividend of -0.22% and the percent impact of the management audit customer dividend.

The table shows that with the exception of 2021, the ARA (*i.e.*, projected GDPPI less customer dividends) increased at a much lower rate than the Companies' increase in O&M expenses.

The Companies are prohibited from recovering their expenses retroactively. Accordingly, if the Companies have insufficient revenues to cover their expenses, they will be put in a position of having to absorb the loss and therefore will not be able to recoup recovery of those costs. Thus, although the PBR Framework provided the Companies a definite incentive to reduce their O&M expenses to retain savings and improve their financial results, the Companies could not reduce overall O&M expenses because they had to ensure safe and reliable service to their customers, fulfill their obligations as a Hawaiʻi public utility, retain a competent and capable workforce and support Hawaiʻi state energy policy. Thus, the design of the ARA did indeed provide an incentive for cost control over the current MRP but unanticipated circumstances resulted in a need for the Companies to address other priorities and requirements which offset the effects of cost control efforts on O&M expense levels. Further, as noted above, if the amount of revenues provided by the ARA are insufficient, it can be difficult for the Companies to timely complete important work.

F. DER Asset Effectiveness

As part of the initial portfolio of Scorecards and Reported Metrics, Decision and Order No. 37787 ("D&O 37787") established reported metrics on DER grid services capability, enrollment, and utilization to address the DER Asset Effectiveness PBR outcome. During the development of these metrics, the Companies raised concerns such as, for the DER Grid Services Capability metric, needing further clarity as to what constitutes a "DER system capable of providing grid services," including whether advanced inverter settings are required and whether water heaters and EVs fall under the scope of applicable DER systems. The Companies proposed that the metric focus on DER systems capable of providing grid services to customers that have a storage system installed.[57] In D&O 37787, the Commission acknowledged the Companies' concerns and stated that it "believes that this is a reasonable starting point for this Reported Metric," that it "expects that further work will be done to determine how to define and measure how other DERs can be captured by this metric," and that "[p]roposals to address this definition and methodology should be raised with the Post-D&O Working Group whenever ready, which the Commission will consider in reviewing future iterations of this Reported Metric."[58]

The following charts report on the Companies' DER grid services capability, enrollment, and utilization metrics. As shown below, from 2021 to 2024, the Companies have annually increased grid services capability and enrollment, and show a generally increasing trend in

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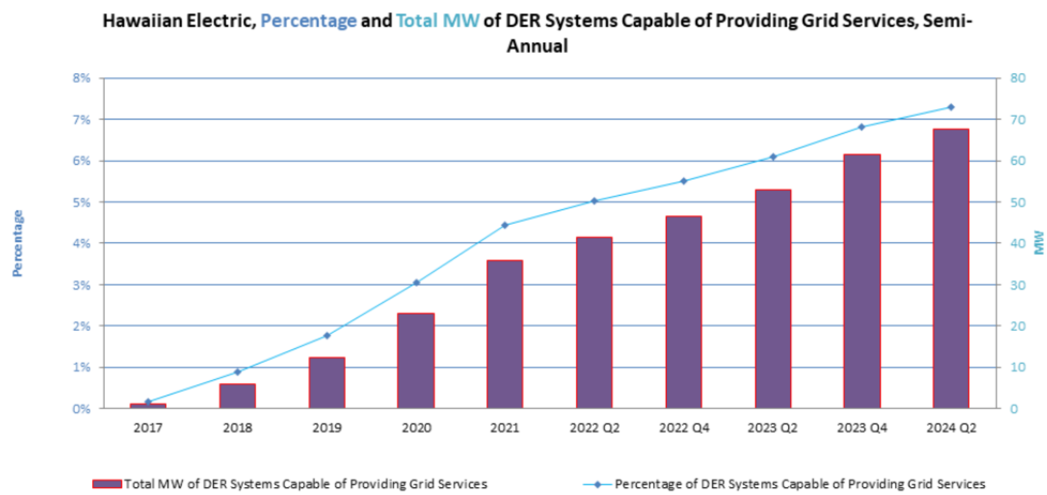
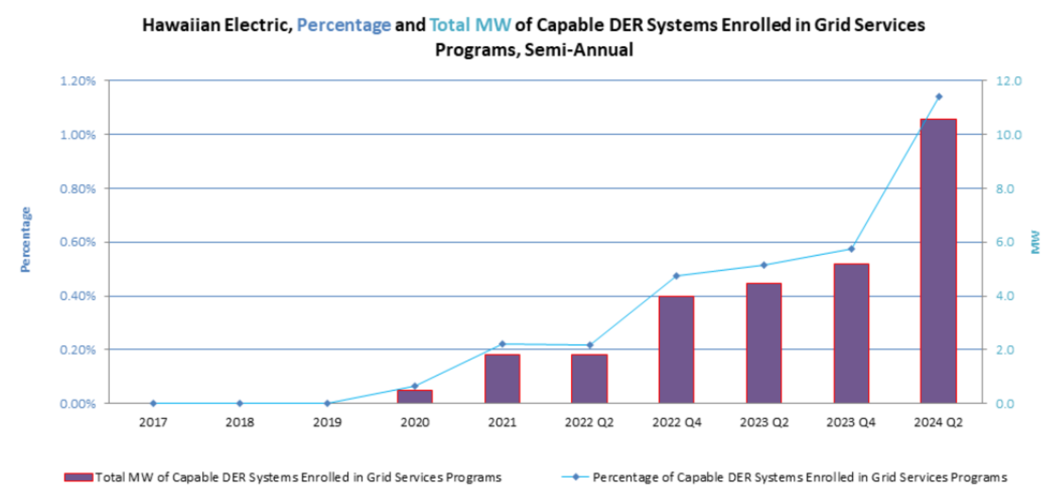
[57] *See* D&O 37787 at 103.
[58] D&O 37787 at 103-104.

utilization, thereby furthering the PBR outcome of DER Asset Effectiveness:[59] The DER resources in these charts are specifically limited to batteries and participation is also limited to grid services programs that are dispatchable, and therefore, do not include any scheduled DER program such as Battery Bonus. The challenges encountered regarding these metrics are further explained below.

DER Grid Services Capability Reported Metric

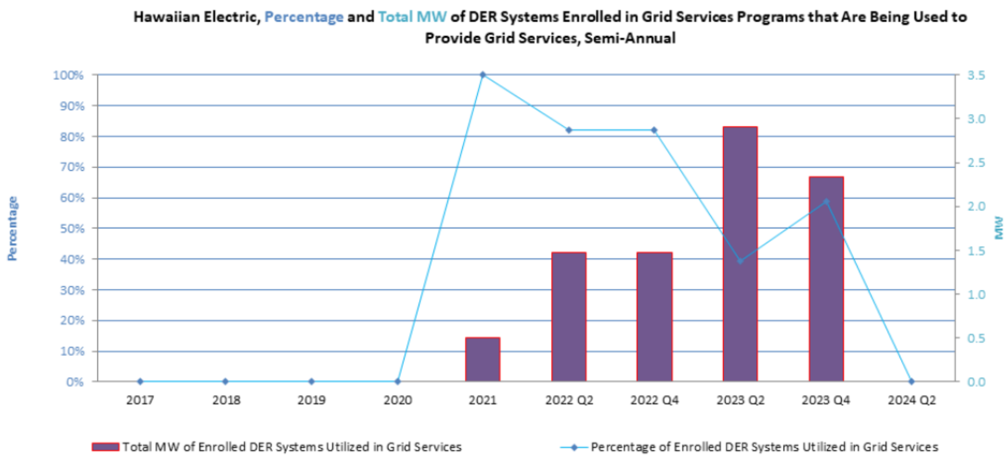


DER Grid Services Enrollment Reported Metric



[59] The DER grid services charts report the Companies' consolidated totals. The underlying DER grid services performance metric data is available at: https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/distributed-energy-resource-(der)-asset-effectiveness.

DER Grid Services Utilization Reported Metric



As authorized by D&O 37787, the Companies limited quantification to batteries for the DER Grid Services Capability metric.[60] As discussed in the Companies' Updated Refined Proposal, the Companies are unable to accurately determine how many water heaters, electric vehicles, or other DER resources are available for each of the islands and the capacity of these resources.[61] Similar to the DER Grid Services Capability metric, the Commission adopted a more focused metric for the DER Grid Services Enrollment metric.[62] The DER Grid Services Enrollment metric is also limited to batteries that are enrolled in grid service programs, such as through an approved GSPA. The GSPA participants with dispatchable battery storage (*i.e.*, dispatchable grid services) are included in the reported metric, whereas Battery Bonus participants are not included in the metric, as Battery Bonus program use is scheduled and not dispatchable.

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[60] D&O 37787 at 103.

[61] *See* Hawaiian Electric Companies' Updated Refined Proposal and Reply Statement of Position, filed April 9, 2021, in Docket No. 2018-0088, at 71-72.

[62] In the Companies' Updated Refined Proposal, the Companies proposed to limit the focus of the DER Grid Services Enrollment metric to: (1) contracted grid services through aggregators that have an approved Grid Services Purchase Agreement ("GSPA"); and (2) successor DER programs currently being developed in the Program Track of Docket No. 2019-0323 that include grid services as a requirement. In D&O 37787, at 194, the Commission acknowledged the Companies' concerns and adopted the Companies' more focused metric.

The DER Grid Services Utilization metric reports on the utilization of DER systems based on a performance factor, defined as the percentage of the delivered capability compared to the total size of battery. As an example, if a customer installs a 5 kW battery and participates in a grid services program, not all 5 kW is available for dispatchable grid services delivery, and the actual delivery would be closer to 2-3kW of committed capacity. The DER Grid Services Utilization metric reports on delivered grid services based on this definition of performance factor.

The DER Grid Services Utilization metric reports zero for Q2 2024 because the aggregator with all of the battery enrollment encountered financial difficulties, eventually defaulted on the GSPA contract and went out of business. Again, Battery Bonus was not included in these charts as Battery Bonus is scheduled and not dispatchable.

In Order No. 41437, the Commission: (1) established the CER Reporting Framework, with the objective of streamlining reporting requirements to increase administrative efficiency and to enable the Commission and Parties to review updates more efficiently;[63] and (2) approved a set of new reporting templates,[64] where program status and metrics similar to PBR Reported Metrics and Schedule A Performance Metrics will be reported in a different format. Consistent with the intent of the CER Reporting Framework, the Companies propose suspending the current DER Asset Effectiveness metrics and Other Resources and Emerging Technologies metrics that separately report on the asset effectiveness of DER and DR, and allow for the new CER reporting template to be the active tool to keep track of CER Asset Effectiveness, to be able to view and measure all customer-sited resources holistically.

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[63] *See* Order No. 41437, issued on December 27, 2024 in Docket No. 2019-0323, at 10.
[64] *See id.* at 9.

G. Capital Formation

The Companies' credit rating performance, discussed above in Section I.A., is critical for capital formation. With regard to other relevant capital formation considerations, the Companies' financing consists of balancing both debt and equity, and targeting a capital structure that supports an investment grade rating. Prior to the financial impacts related to the Maui Wildfire, the Companies maintained a ratio of combined preferred stock and common equity to total capitalization ("Equity Capitalization") of about 58%. As of December 31, 2024, the Companies' Equity Capitalization was approximately 38%, which is well below the level that the financial markets would consider investment grade. Consistent with approvals in the Companies' last rate cases,[65] the Companies plan to manage their capital structures to achieve Equity Capitalization of at least 58%.[66] Exposure to large third-party liabilities stemming from the Maui Wildfire has negatively impacted the Companies' Equity Capitalization and the Companies intend to restore their Equity Capitalization to investment grade levels over time. The Companies' Equity Capitalization will increase as each litigation settlement payment is made to the plaintiffs.

Restoring the balance of external financing (*i.e.*, mix of equity and debt funding) will help the Companies improve their financial metrics. Strong financial metrics are necessary for the Companies to improve their current ratings and lower the cost of financing.

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[65] In the Hawaiian Electric 2020 test year rate case final decision and order, the Commission approved revenue requirements based on an equity percentage of 58.0%. *See* Decision and Order No. 37387 (at 41-42) issued on October 22, 2020 in Docket No. 2019-0085. In the Hawaiʻi Electric Light 2019 test year rate case final decision and order, the Commission approved revenue requirements based on an equity percentage of 58.0%. *See* Decision and Order No. 37237 (at 83) issued on July 28, 2020. In the Maui Electric 2018 test year rate case final decision and order, the Commission approved revenue requirements based on an equity percentage of 58.0%. *See* Decision and Order No. 36219 (at 24-26) issued on March 18, 2019.

[66] *See* HECO-2607, pages 1-2, filed August 21, 2019, in Docket No. 2019-0085; HELCO-2212, pages 1-2, filed December 14, 2018, in Docket No. 2018-0368; and MECO-2209, pages 1-2, filed October 12, 2017, in Docket No. 2017-0150.

In January 2025, the Companies have requested Commission approval to issue taxable debt in Docket No. 2025-0151 and equity in Docket No. 2025-0155.[67] These applications, if approved by the Commission, will help the Companies achieve their target capital structure over time which benefits customers in the form of borrowing rates that are lower than they otherwise might have been, while improving the financial strength of the Companies, assuming constant market conditions.

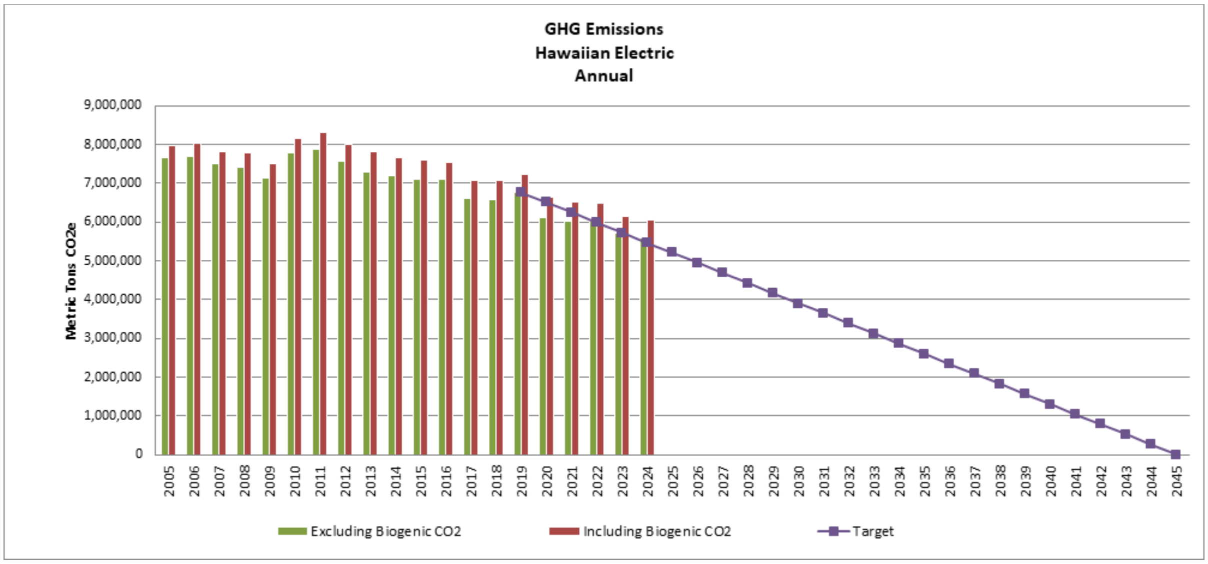
The ability to attract capital at a reasonable cost, a prerequisite to achieving the Companies' goals related to public safety, grid reliability and resilience, grid modernization, and decarbonization, and other qualitative and quantitative factors are relevant to create an environment that supports capital formation. For example, Moody's ratings grid scorecard considers the (i) regulatory framework (25% weighting), which assesses the strength of the legislative and regulatory environment and the consistency and predictability of regulation, (ii) ability to recover costs and earn returns (25% weighting), which assesses the timeliness of recovery of operating and capital costs and sufficiency of rates and returns, (iii) diversification (weighted 10%), which assesses the Companies' market position and generation and fuel diversity, and (iv) financial strength (weighted 40%), which assess cash flow metrics in relation to debt, capital structure, and cash flow coverage metrics.

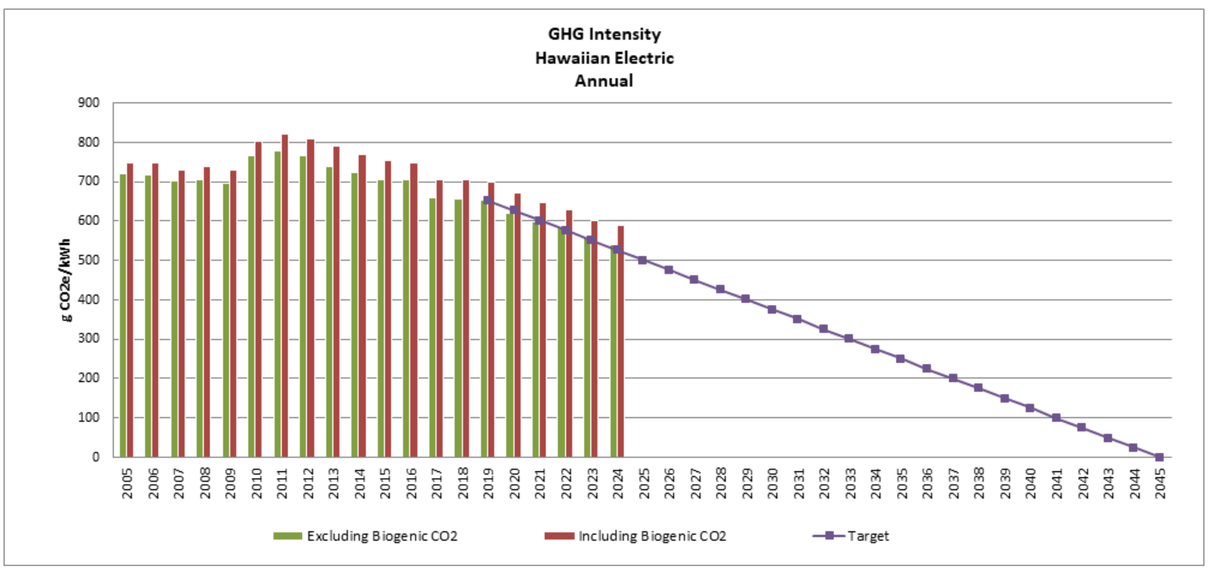
H. Greenhouse Gas ("GHG") Reduction

The Companies maintain that they have performed well with regard to the PBR Outcome of GHG Reduction. The Hawaiian Electric Companies are committed to significantly reducing carbon emissions by adding renewable generation to their island grids and retiring oil-fired

[67] *See* the Companies' taxable debt application, filed on January 17, 2025 in Docket No. 2025-0151, at 16-19, and the Companies' common stock application, filed on January 27, 2025 in Docket No. 2025-0155, at 6-11, for the detailed discussion on their credit ratings and capital structures.

power plants.[68] As shown in the graphs below, GHG Emissions and GHG Intensity constantly declined under MRP1.[69] The GHG emissions scorecard reports emissions in carbon dioxide equivalent ("CO2e") emissions per year in metric tons from all sources that supply electricity to the O‘ahu, Maui County and Hawai‘i Island grids on a consolidated basis, which includes independent power producers.





68 *See* https://www.hawaiianelectric.com/carbonfree.

69 Source: https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/ghg-reduction.

The reduction in GHG Emissions and GHG Intensity was accomplished through the integration of substantial amounts of both utility-scale renewable projects and customer-owned distributed energy resources and the retirement of fossil fuel generation, as identified in the table below.

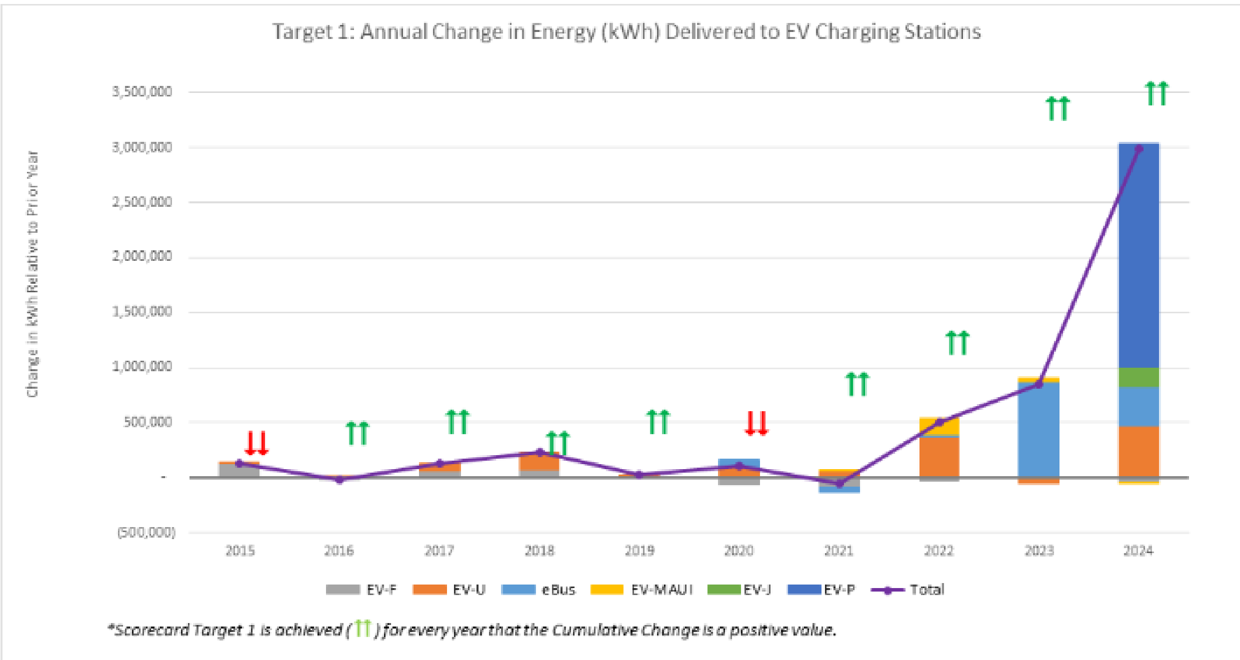
2021	New private rooftop system installations totaled 53 MW
2022	Mililani I Solar 39 MW solar plus 156 MWh battery storage project placed in service New private rooftop system installations totaled 40 MW AES Coal Plant retired
2023	Waiawa Solar 36 MW solar plus 144 MWh battery storage project placed in service Waikoloa Solar 30 MW solar plus 120 MWh battery storage project placed in service Kapolei Energy Storage 185MW/565MWh standalone storage placed into service New private rooftop system installations totaled 65 MW Honolulu Units 8 and 9 retired[70]
2024	AES West Oʻahu Solar 12.5 MW solar plus 50 MWh battery storage project placed in service AES Kuihelani 60 MW solar plus 240 MWh battery storage project placed in service Kupono Solar 42 MW solar plus 168 MWh battery storage project placed in service New private rooftop system installations totaled 61 MW Waiau Units 3 and 4 retired
2025	Hale Kuawehi Solar 30 MW solar plus 120 MWh battery storage project placed in service

I. Electrification of Transportation ("EoT")

The Companies' performance under the electrification of transportation outcome, as measured by the Measured EV Load (Energy), Estimated EV Load, and EV Count Scorecards below, have successfully tracked the growth of EV adoption.[71] The year-over-year growth during MRP1 can be attributed to several factors including the Companies completing installation of 25 metered accounts under Schedule EV-U, the addition of the four chargers under Schedule EV-MAUI, the continual improvements in repair, operations, and maintenance of the Companies' chargers leading to increased availability and utilization of the chargers,

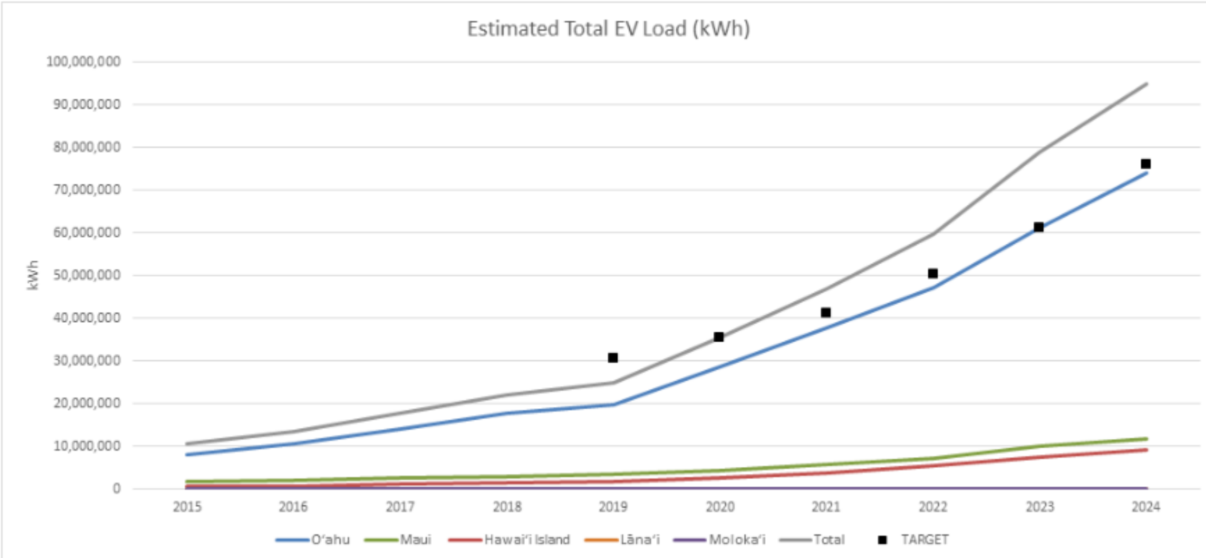
[70] Honolulu Units 8 and 9 were deactivated on January 31, 2014.
[71] Available at: https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/electrification-of-transportation.

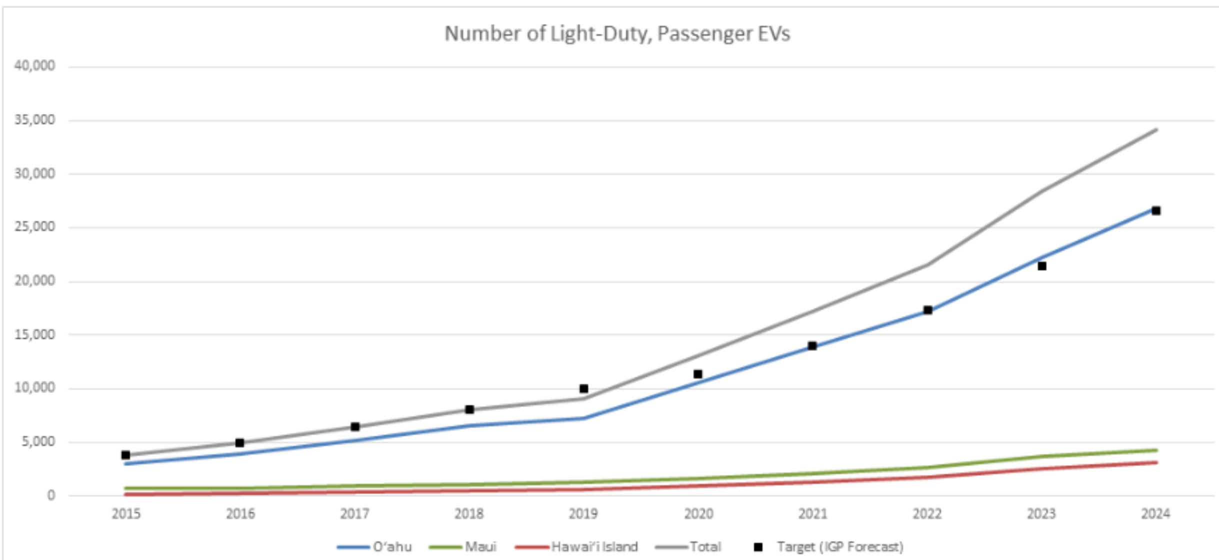
implementation of Schedule EV-J and Schedule EV-P, increases in EV ownership across the Companies' service territories, and increased utilization of EVs in high mileage industries such as rideshare and rental cars. The Companies' Consolidated Annual EoT Report filed in Docket No. 2018-0135 and Annual Pilot Update Report in Docket No. 2022-0212 provide additional information.



Target 1: Annual Change in Energy (kWh) Delivered to EV Charging Stations											
Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Total	126,659	(13,896)	125,669	227,972	25,859	102,841	(53,403)	503,564	847,380	2,991,170	3,255,766
EV-F	126,657	(15,589)	57,765	70,953	(6,260)	(64,174)	(82,350)	(34,851)	15,029	(37,082)	(41,421)
EV-U	2	1,693	67,904	157,019	32,119	92,715	60,564	373,187	(52,568)	473,085	978,422
eBus	-	-	-	-	-	74,300	(44,750)	17,052	849,676	356,383	220,492
EV-MAUI	-	-	-	-	-	-	13,133	148,176	35,242	(5,765)	(6,737)
EV-J	-	-	-	-	-	-	-	-	-	180,828	(62,557)
EV-P	-	-	-	-	-	-	-	-	-	2,023,721	2,167,567

**Scorecard Target 1 is achieved for every year that the Cumulative Change is a positive value.*



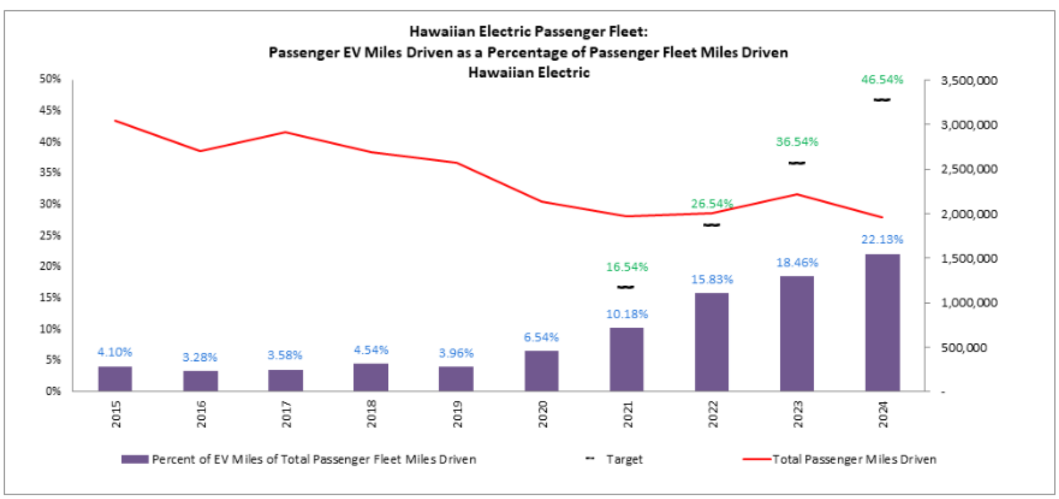


The Companies' reporting metrics on EoT are many and substantial. The Companies suggest that in the interest of administrative efficiency and lessening resource burden, the number of these metrics should be reconsidered and reduced. Specific consideration should be given to whether the Measured EV Load (Demand) Scorecard and Ride Share Fueling Hubs Reported Metric are necessary since this data is not available and there was no data provided in MRP1. Additional discussion and clarification on this scorecard and metric are necessary before being established in MRP2.

Fleet Electrification Scorecard

The Companies are also committed to convert every passenger car, SUV, light pickup, and minivan in their fleet to plug-in electric by 2035 ("2035 commitment").[72] This pledge is part of a nationwide collaborative commitment to the electrification of transportation by many member companies of the Edison Electric Institute, a national organization of investor-owned utilities. This commitment has been tracked through the Fleet Electrification Scorecard as shown in the graph below.[73] During MRP1, there have been unforeseen challenges with meeting the 10% annual increase in EV miles as a share of total passenger EVs such as higher than expected prices for new, long-range battery electric vehicles or plug-in electric vehicles and limited inventory within required specifications of replacement types. These factors are not in line with the Companies' responsibility to be fiscally prudent and accountable to its customers.

While the Companies were below the annual targets during MRP1, the Companies remain committed to meet their 2035 commitment and plan to continue to monitor vehicle utilization and remove under-utilized vehicles, and increase the number of chargers onsite, which will support the growing plug-in electric fleet.



[72] *See* https://ngtnews.com/hawaiian-electric-commits-to-complete-fleet-electrification.

[73] Available at: https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/electrification-of-transportation.

J. Resilience

Under PBR, this outcome has been tracked in terms of National Incident Management System ("NIMS") certifications and Emergency Response training.[74] During the 2020 work-from-home period, the Companies achieved over 90% completion of required NIMS certifications. From 2021-2022, new hires and remaining employees completed their training, and in 2023 the extended activation of the Maui Wildfire Incident Management Team ("IMT") led to a slight increase in certifications, which tapered off in 2024. In addition to NIMS certifications training, the Companies also administered a Public Safety Power Shutoff ("PSPS") program course to 40% of the workforce in 2024.

Emergency Response Training includes annual exercises and IMT activations, both of which have significantly increased since 2021. The Companies' COVID IMT ran from 2020 to 2022, and the 2023 Maui Wildfire IMT lasted about four months. Additional training and tabletop exercises were introduced with the Companies' PSPS program, contributing to the rise in IMT activations in 2024.

Going forward, the Resilience outcome metrics are ripe for reconsideration. Since the beginning of MRP1, the Companies began to implement their T&D Resilience Program for which the Commission approved the commitment of expenditures in Docket No. 2022-0135. Metrics relating to this effort may be more meaningful. The Companies also intend to propose that Public Safety be a priority outcome for MRP2. This category would include wildfire mitigation efforts under the Companies' Wildfire Safety Strategy (currently under review by the Commission).

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[74] *See* https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/resilience.

III. How Specific PBR Mechanisms Have Performed During MRP1 and Which Should Be Examined During Phase 6 for Potential Modification

Consistent with the Companies' evaluation of the PBR Framework and submission of completed Regulatory Assessment Templates on January 17, 2025, and the Commission's February 14, 2025 Working Group Meeting to Discuss PBR Mechanisms, the Companies provide their evaluation of how the specific PBR mechanisms identified by the Commission have performed during MRP1 and which should be examined during Phase 6 for potential modification.

A. Multi-Year Rate Period ("MRP")

At the present time, the Companies do not recommend a change to the five-year period for the next MRP, but that position may change depending on whether and how other elements of the PBR Framework will change. The *Hawaiian Electric Companies Feedback on Scope of Year 4 Review*, submitted on March 1, 2024, stated the Companies' position on the length of the MRP (at 2):

> As a preliminary view, in such a dynamic energy and climate change environment, the Companies believe five years should probably be the maximum length of any MRP. Conversely, three years may be too short to attain some of the PBR cost and resource-saving benefits of avoiding more frequent rate-setting or review proceedings.

Generally, the elements of the PBR Framework should be assessed in total to ensure that collectively they are consistent with the goals of PBR, support the Companies' financial integrity and provide the Companies an opportunity to earn their authorized rates of return, advance State energy policy and provide safe and reliable electric service. Whether the length of the MRP should change would depend on the extent to which the PBR Framework for the next MRP will allow the Companies' a realistic opportunity to earn their authorized returns.

First, the results of the planned 2026 test year consolidated rate case will need to be considered.

Second, the PBR framework would need to allow the Companies the opportunity to achieve their authorized rates of return during MRP2. If not, the MRP period should be shortened to allow the Companies to request additional rate relief sooner through a rebasing proceeding. The Companies' position is that an X-Factor of zero and the EPRM mechanism as currently approved will not allow the Companies to fully recover their costs in MRP2. This brief shows that the Companies' ratemaking returns during MRP1 have been below authorized,[75] which supports the Companies' position that the scope of the EPRM would need to be modified for MRP2, and if the EPRM is not modified, the X-Factor would need to change to allow the Companies additional revenues to recover their costs in MRP2. In addition, the following measures should be implemented for the next MRP:

- The suspension of the earnings sharing mechanism should be terminated for MRP2 so that the Companies would be able to obtain a measure of relief if it triggers the ESM on the downside or share profitability with customers if it triggers the ESM on the upside.
- The management audit customer dividend in the ARA should be terminated. The Companies have made changes to their operations to respond to the recommendations of the management audit and those changes would be reflected in the revenue requirement for the 2026 test year rebasing.
- There should be an annual mechanism to true-up the I-Factor to actual inflation rates. This will ensure that the ARA is appropriately adjusted up or down according to how actual inflation compares to the projected GDPPI used to calculate the ARA.

If the above measures are not implemented for MRP2, there should be consideration to shorten the MRP from the current five years.

[75] *See* the Companies' consolidated ratemaking ROE for 2021-2024 in Section I.B., above.

B. ARA I-Factor

Actual costs during MRP1 have far exceeded inflationary adjustments provided by the PBR Framework. The ARA was not designed to capture or recover actual changes in the Companies' cost of service. For the period 2021-2024, there have been deficiencies in capital investment and O&M recovery for all three Companies.[76] Additionally, the ARA does not cover changes in the business that were not originally contemplated in the Companies' cost of service rate cases or areas for which actual costs have increased significantly above projected GDPPI levels. For example, the additional investment in capital and expenses needed to address wildfire risk and to improve public safety are not reflected in the current target revenues (also *e.g.*, insurance premiums, supply chain cost increases).

To improve the I-Factor so that it would function as intended, an annual inflationary true-up adjustment mechanism should be incorporated. The inflationary adjustment mechanism would calculate an adjustment that would true-up or true-down the Commission's approved compounded portion of the ARA Adjustment to account for actual inflation. In addition, it may be appropriate to consider a blended inflationary adjustment (blending in an additional inflation index into the inflationary adjustment, such as the employment cost index ("ECI") for utilities, should be explored as the ECI would more accurately capture the inflationary pressures related to labor).

C. ARA X-Factor

One way to provide supplemental revenues to the Companies to support necessary and prudent large "business-as-usual" capital investments would be to expand the eligibility requirements of the EPRM, so that large capital projects, regardless of the nature of the project,

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[76] *See* the Companies' consolidated ratemaking ROE for 2021-2024 in Section I.B., above.

would be eligible for recovery. As explained above, one reason the X-Factor was set at zero was the intent that a case-by-case-review of large capital projects via EPRM was a better and more practical means to address those investments rather than by including a fixed X-Factor revenue adjustment to account for them. At the same time, large, so-called business as usual capital projects were excluded from eligibility for MPIR and later EPRM recovery. To address this shortfall in recovery, the Companies proposed in Phase 2 of this proceeding an X-factor of -1.32 and requested clarification on whether certain types of projects would be eligible for EPRM recovery.[77] However, the X-Factor was set at zero and the Commission would decide on eligibility on a case-by-case basis. As Section I.D. above explains, subsequent decisions in EPRM dockets effectively narrowed the criteria for eligibility and recovery through the EPRM. Thus, a mechanism to account for large "spikey" business-as-usual capital investments, which by acknowledgement are not well-suited for fixed formula-based recovery, is lacking in the PBR Framework and should be addressed and provided. If not addressed by EPRM modification, another way would be to reexamine the X-Factor and establish a negative X-Factor as the Companies' quantitative analysis in Phase 2 of the PBR docket concluded and as other jurisdictions have approved.

D. ARA Z-Factor

In the Companies' view, the Z-Factor worked as intended for the COVID-19 impacts. The Companies do not presently perceive need for modifications to the Z-Factor. However, the Maui Wildfire impacts have been far-ranging, including the effects on the Companies' liquidity, access to capital, the cost of capital, and the longer-term costs of wildfire mitigation, resilience

[77] *Post-Hearing Brief of the Hawaiian Electric Companies*, filed on October 19, 2020, Docket No. 2018-0088, at 16.

and other public safety and disaster response measures. If not addressable by the Z-Factor, other aspects of the PBR Framework may need to be modified to address these impacts.

PBR modifications are being considered during a time of significant economic and social uncertainty and unpredictability. Changes in law or policy, as evidenced by an historic amount of presidential executive orders and tariffs, may directly or indirectly increase Project and other operation costs in material and unanticipated ways. Thus, the PBR Working Group must consider whether the Z-Factor or some other mechanism can address this volatility and uncertainty. A five-year rate case stay out period can work in relatively stable times. Conversely, added flexibility in terms of potential adaptable cost recovery mechanisms is prudent in times like these. Further discussion is warranted.

E. ARA Customer Dividend

The 22-basis point Customer Dividend reduction should be revisited. Justification for the amount seemed somewhat arbitrary and the amount should also be considered in the context of the entire ARA formula puts-and-takes. The Companies are evaluating a modification to this component, especially in light of the fact that with one exception in 2022, the Companies have not been able to earn their authorized returns for over a decade.

There should be a balance between the customer dividends and other elements of the PBR Framework. For example, if the X-Factor is set artificially high (thus providing less revenues for recovery) and the EPRM does not provide for sufficient capital recovery of needed plant investments, there should be consideration of whether customer dividends should be reduced or eliminated since the Companies' ability to flow through savings to customers will be constrained or eliminated.

Further, the Companies' position is that the customer dividend for the management audit savings commitment of $6.6 million per year (including revenue taxes) for the three Companies should be terminated. In Order 41575, the Commission ordered that the Companies' target revenues shall be rebased for MRP2 and that the rebasing shall be effectuated via a rate case-like procedure. The Companies have made changes to their operations to respond to the recommendations of the management audit and those changes would be reflected in the revenue requirement for the 2026 test year rebasing. The management audit dividend should terminate concurrent with the effective date of new rates that result from an interim decision and order in the upcoming 2026 test year rebasing.

The total customer dividends consisting of a negative adjustment of 0.22% of adjusted revenue requirements compounded annually and a flow through of the "pre-PBR" management audit savings commitment of $6.6 million per year (including revenue taxes) returned to customers are expected to be approximately $87 million during MRP1 (June 1, 2021 – May 31, 2026) and $101 million during MRP1 and the interim period (June 1, 2021 – December 31, 2026).[78]

F. EPRM

As discussed above in Section I.D., the scope and eligibility requirements for EPRM recovery should be revisited. With the ARA (the X-factor in particular) and the EPRM mechanism as currently configured, the consolidated Companies were not able to achieve their authorized return on equity in MRP1, as shown in Section I.B. above. Therefore, the EPRM should be examined in Phase 6 for possible modification, specifically to expand the scope of

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[78] The total customer dividends of $87 million and $101 million are estimated using the following assumptions: (i) 2.00% GDPPI for 2026, and (ii) the management audit savings commitment continues to be refunded in 2026.

eligibility for the EPRM. If the Commission does not allow a broadening of the EPRM eligibility, the X-factor should be examined in the alternative to address the shortfall in recovery.

G. Revenue Balancing Account

In D&O 37507 (at 191), the Commission stated the following:

> Upon review, the Commission finds it is reasonable to maintain the RBA to ensure that approved accrued revenues are reconciled through an annual rate adjustment reconciliation. Similar to its current function, under the PBR Framework, the RBA will serve to track and record variances between the Companies' target revenues and actual collected revenues. In accordance with tariffs as amended, target revenues and the RBA Rate Adjustment will be updated according to the annual review cycle, and will reflect reduced lag regarding accrual and collection of adjustments to target revenues, as provided in Section IV.E.3, infra. This will help ensure that appropriate adjustments to the Companies' annual revenues, pursuant to operation of the ARA and other PBR Mechanisms are timely reflected in the Companies' target revenues.

The Companies recommend that the RBA mechanism be retained for MRP2 for the reasons discussed by the Commission above in D&O 37507, and that the RBA continue to operate as currently designed (*e.g.*, the RBA Rate Adjustment, effective on January 1 would recover the preceding September 30 balance).

H. Innovative Pilot Process

The Innovative Pilot Process has provided the Companies and stakeholders with opportunities to investigate innovative ideas and scale-up decisions. To date, this process has been a useful mechanism for the Companies to conduct innovative pilot projects at a scale that enables efficient use of resources and funding. The project findings from the three in-flight and two recently concluded pilots are valuable and have informed lessons learned and areas for pilot project modifications and improvement.

The Companies view the Innovative Pilot Process as an important part of the PBR Framework and the mechanism should be continued unmodified beyond the end of MRP1. The Companies' current financial situation has impacted which pilot ideas were developed and proposed under the Innovative Pilot Process. As a result, the Companies have not been able to fully utilize the Innovative Pilot Process as they originally intended and to learn and explore as much as they expected. Continuing the Innovative Pilot Process will provide the Companies and stakeholders with flexibility to quickly test new innovative technologies, programs, and ideas. Pilots will be consistent with the Companies' Innovation Pilot Framework Workplan and the Commission's guidance on Notices of Intent submitted under the process.[79] In addition, pilots have staggered implementation schedules and variable costs, and pilot review, implementation, and cost recovery are better suited to be separate from the re-basing process. The assessment of no modification is based on the assumption that the cost recovery of projects under the Innovative Pilot Process will continue for the period between the end of MRP1 (May 31, 2026) and the beginning of MRP2 (January 1, 2027), and into MRP2, so that implementation and cost recovery of existing pilots will continue uninterrupted from one MRP to the next.

I. Earnings Sharing Mechanism

A reopening or review of the PBR terms may be triggered if the Companies credit rating outlook indicates a potential credit downgrade below investment grade status, or if their achieved ratemaking ROE enters the outermost tier of the ESM. On August 31, 2023, the Commission issued Order No. 40222 temporarily suspending the ESM until further notice. It may be prudent to consider if and how the intent of this order should be reflected in the express language of this mechanism. The Companies do not yet have a comprehensive position on whether the ESM has

[79] *See* Order No. 40129, issued on July 28, 2023, in Docket No. 2022-0212, at 6-9.

worked as intended and what would be required to perform an assessment of whether the structure of the ESM should be modified.

However, the Companies propose that the Commission consider terminating the suspension of the ESM in Phase 6 of the PBR proceeding. Order No. 40222 stated the following:[80]

> To be clear, the Commission's actions in this Order are for the specific and limited purpose of addressing the unintended consequence of customers potentially bearing costs for the Maui Wildfires through the ESM without prior review by the Commission. Pending more information about the situation on Maui and the Wildfires' impacts, the public interest is not served by the ESM being implemented automatically and without careful review by the Commission and relevant parties.

Since the wildfires occurred in August 2023, many of the issues regarding the impacts and the restoration of damaged facilities and the planning for wildfire mitigation and recovery have either been addressed or there is a plan or a process for addressing them. Once the Companies revenues are rebased in the upcoming 2026 test year rate case, it appears appropriate to terminate the suspension of the ESM concurrent with the beginning of MRP2, if not sooner.

J. Re-Opener Provision

A reopening or review of the PBR terms may be triggered if the Companies credit rating outlook indicates a potential credit downgrade below investment grade status, or if their achieved ratemaking ROE enters the outer most tier of the ESM.[81]

There may be a need for clarification on the triggering events for a re-opener (*e.g.*, whether the potential for a credit rating downgrade or the ratemaking ROE entering the

[80] Order No. 40222, Docket No. 2018-0088, at 10.
[81] *See* D&O 37507 at 33-34.

outermost tier of the ESM can trigger a re-opener regardless of cause, such as resulting from a wildfire) and whether additional triggering events may be needed.

K. Biannual Review Cycle

In establishing the bi-annual schedule, the Commission addressed the concern about the administrative strain on resources and stated as follows in D&O 37507:

> Consistent with the PBR principle of improving administrative efficiency, the annual review cycle should be streamlined and standardized to the greatest extent possible, to avoid undue surprises, substantive dispute, or confusion regarding implementation of the PBR Framework. Stated plainly, these fall and spring reviews should be predominantly ministerial in nature, and primarily consist of verifying target revenue adjustments in an arithmetic fashion.[82]

Additionally, the Commission took into account the Companies' request to reduce lag and improve cash flow, and the bi-annual schedule incorporates two annual opportunities for RBA Rate Adjustments.

The Companies recommend the bi-annual review schedule be retained for MRP2 for the following reasons:

- <u>Supports the PBR principle of improving administrative efficiency</u> by reducing the administrative strain on resources. The bi-annual schedule operated as designed and has been predominantly ministerial in nature, primarily consisting of verifying target revenue adjustments in an arithmetic fashion.
- <u>Takes into account the Companies' concern to reduce lag and improve cash flow</u> with two annual opportunities for RBA Adjustments.
- <u>Establishes earlier annual reporting of 1) Pilot, 2) PIM / SSM performance, and 3) EPRM recovery</u> ahead of the spring revenue filing. This allows the Consumer Advocate and the Commission additional time to review these more complex areas and reduces the administrative strain on resources than if everything were submitted as a single package by March 31 with an effective date of June 1.

[82] D&O 37507 at 202.

L. Overall PIMs

Section I. E. above discusses the Companies' perspective on PIMs during MRP1. For MRP2, the Companies continue to agree with the Commission Staff Proposal that the portfolio of PIMs should be limited in number and in the number of priority outcomes the PIMs would address. A portfolio of PIMs with a narrowed focus would be conducive in directing limited resources to priority outcomes more effectively. Additionally, as explained above, the portfolio of PIMs should be based on objectives that are substantially within the Companies' control and offer a realistic chance to earn meaningful rewards to achieve 150-200 basis points of ROE as originally contemplated by the Commission.

M. T&D Reliability PIM

As discussed in the Reliability section above, the Companies' performance tracked the intent of the PIM (to maintain historic levels of reliability) for the first few years but has had a worsening trend following implementation of wildfire mitigation efforts. On December 18, 2024, the Commission issued Order No. 41256 *Granting the Hawaiian Electric Companies' Request for Partial Temporary Suspension and Modification of the Transmission & Distribution Reliability Performance Incentive Mechanisms*. On January 15, 2025, the Commission issued Order No. 41478 *Granting the Hawaiian Electric Companies' Motion for Clarification or in the Alternative Partial Reconsideration of Order No. 41256 filed on December 30, 2024*.

In accordance with Order No. 41256, on March 31, 2025, the Companies filed a preliminary report on their experiences with implementing the Protective Measures and how they have impacted the Companies' T&D SAIDI and SAIFI performance on Wildfire Risk Circuits, and an update on the Companies' steps to mitigate the reliability impact of the Protective Measures. The Companies will submit similar reports in June 2025 and September 2025.

The Companies will engage the PBR Working Group after August 31, 2025 to discuss the results of analyses on data collected, whether sufficient data have been collected to justify reinstatement of T&D Reliability PIMs for Wildfire Risk Circuits or for all (Non-Wildfire Risk and Wildfire Risk) Circuits combined, how T&D Reliability PIMs should be designed going forward, and when such T&D Reliability PIMs should take effect.

N. Call Center PIM

The Companies' call center performance met targeted expectations during MRP1. It was within the deadbands of the PIM during MRP1 and tracked the intent of the PIM (to maintain historic levels of call center performance). Order No. 40860 issued on June 24, 2024, in Docket No. 2018-0088 ("Order 40860") approved a modification to the Call Center PIM which took effect on August 1, 2024. In Order 40860, the Commission observed the following:

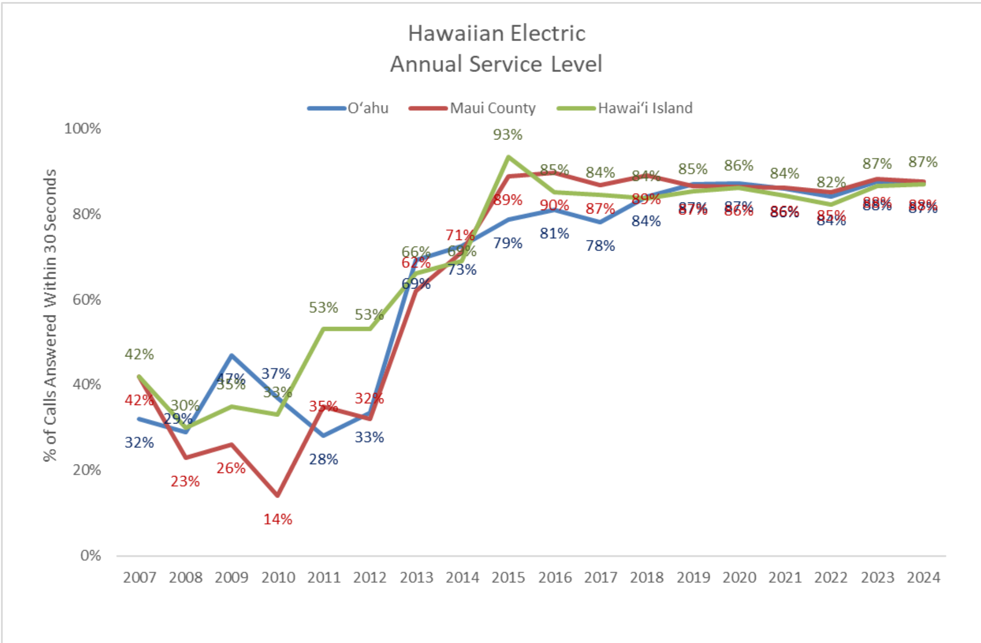
> The Commission previously expressed concern that a consolidated target may not result in uniform Call Center service across individual Companies.[83] However, recent data reflects that the performance under the PIM for all three Companies has been converging in recent years, such that Company-specific targets may no longer be necessary. Since 2019, performance across all three Companies has been nearly uniform.[84, 85]

Circumstances have changed since the Commission originally approved the Call Center PIM. In Order No. 34514 approving the Cell Center PIM, the Commission stated:

> 26. The HECO Companies acknowledge that call center performance for the Companies "has been relatively low," but that the Companies "are actively addressing this problem by upgrading their information systems and customer interfaces."[86]

[83] *See* Docket No. 2013-0141, Order No. 34566, Addressing the Hawaiian Electric Companies' Motion for Partial Reconsideration of Order No. 34514 with Respect to the Performance Incentive Mechanisms, filed on May 24, 2017, at 6-7.
[84] *See* Hawaiian Electric RSOP at 9 (table reflecting "Annual Service Level" for all three Companies).
[85] Order 40860 at 12-13 (original footnotes included).
[86] Order No. 34514 issued on April 27, 2017, in Docket No. 2013-0141 at 35.

Since the issuance of Order No. 34514, the Companies performance has improved and converged as observed by the Commission in Order 40860.[87]



As a result, the Companies propose that the Call Center PIM be discontinued. The Companies could instead continue to track their Call Center performance through the Service Level (Percentage of Customer Calls Answered Within Thirty Seconds) metric on their website.

O. DER Interconnection Approval PIM

The Interconnection Approval PIM was well designed in that it incentivized the Companies to achieve continued, annual improvements and efficiencies in the interconnection experience for customers.[88] Section II.C. on Interconnection Experience and the Companies' annual February Notice Transmittals discuss the Companies' interconnection approval performance during MRP1.[89]

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[87] Source: https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/customer-service. "Service Level" (Percentage of Customer Calls Answered Within Thirty Seconds) historical data.
[88] *See* the Companies' response to PUC-Parties-IR-18, subparts a and b, filed September 20, 2023, at 1-5.
[89] The Companies' Interconnection Approval PIM performance for the 2021 to 2024 evaluation periods is discussed in the "Annual PIM and SSM Performance Review" section of the February Notice Transmittals filed in Transmittal Nos. 22-01, 23-01, 24-01, and 25-02.

Order No. 40462[90] extended the Interconnection Approval PIM through 2024 to December 31, 2024 without modification to the original PIM targets and rewards/penalties set by the Commission when this PIM was initiated. This PIM sunset and expired on December 31, 2024. The Companies are open to considering modifications to the PIM as a part of the Performance Working Group ("PWG") and Phase 5/6 process.[91] More specifically, the Companies suggest considering a potential continuation of a similar PIM since this PIM was well designed. However, prior to considering any modifications, the Companies recommend first discussing with the working group whether an interconnection approval PIM is still needed given that, as previously referenced by the Companies and the Commission, overall interconnection times for customers still remain long compared to duration times for work within the Companies' control that were measured as a part of this PIM. In addition, if a new PIM were to be developed as part of the PWG process, the Companies request that any new measurement period start after a reasonable amount of time after the Commission's decision on the PIM so that the Companies can adequately prepare and prioritize resources.

P. Grid Services PIM

The interim Grid Services PIM incentivized the increased acquisition of grid services, thereby furthering the regulatory outcome of DER Asset Effectiveness. As explained further herein, the Companies support the development of a successor DER acquisition PIM.

D&O 37507 established the Grid Services PIM on an interim basis to promote the PBR outcome of DER Asset Effectiveness, as well as Grid Investment Efficiency by incenting the acquisition of grid services from DERs.[92] The interim Grid Services PIM rewarded the

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[90] Order No. 40462, Addressing Performance Incentive Mechanisms Related to Distributed Energy Resources, issued on December 26, 2023, in Docket No. 2018-0088.
[91] *See* Order No. 40932, issued on July 30, 2024, in Docket No. 2018-0088, at 5-7.
[92] D&O 37507 at 106.

acquisition of grid services through procurement or programs acquired between January 1, 2021 and December 31, 2023.[93] Eligible grid services included Fast Frequency Response ("FFR"), load build, and/or load reduction services.[94] The scope of eligible grid services were grid services acquired with approval by the Commission, including: (1) contracts such as GSPAs; (2) measures and programs approved in the DER docket (Docket No. 2019-0323), including the SDP programs[95] on O'ahu and Maui; (3) O'ahu's Fast DR Program up to the 7 MW cap; and (4) innovative measures or new concepts proposed by the Companies.[96]

As discussed in the February Notice Transmittals:[97]

- The Companies did not earn a reward in 2021 for the interim Grid Services PIM because they did not submit for Commission approval a procurement contract or program that would qualify for the PIM reward in the 2021 evaluation period.
- During 2022, the Companies reviewed, verified, and completed SDP amendments for load reduction grid services on O'ahu, resulting in monthly increases in installed committed capacity on O'ahu, and Hawaiian Electric qualified for PIM incentives for the 2022 evaluation period based on the increase in load reduction grid services capacity.
- During 2023, the Companies similarly completed SDP amendments resulting in monthly increases in load reduction grid service capacity for both Oahu and Maui, qualifying for PIM incentives. For the 2023 evaluation period, the Companies also qualified for a PIM incentive for the execution of GSPA3 as approved by the Commission.[98,99]

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93 Decision and Order No. 38429 ("D&O 38429"), issued on June 17, 2022, in Docket No. 2018-0088, at 58, extended the interim Grid Services PIM through December 31, 2023.
94 D&O 37507 at 107.
95 The "SDP" programs are also referred to as "Battery Bonus."
96 D&O 38429, at 58, expanded the scope of eligible grid services to include newly acquired committed capacity in O'ahu's SDP and Fast DR programs, and Maui's SDP program, at increased load reduction incentive rates set forth in D&O 38429.
97 *See* Notice Transmittal Nos. 22-01, 23-01, and 24-01.
98 *See* Hawaiian Electric Tariff Sheet No. 98D.3 ("Acquisition of Grid Services shall be determined based on criteria to be approved by the Commission, including but not limited to the execution of a binding commitment for binding contracts such as GSPA or annual enrollment of customers in an eligible grid services program as approved by the Commission.").
99 Decision and Order No. 40082 ("D&O 40082"), issued on July 12, 2023, in Docket No. 2022-0041, approved GSPA3 contingent on a contract modification. D&O 40082 (at 58) stated: "To the extent that the approved renegotiated contract aligns with the requirements of the existing PIM as outlined in Decision and Order Nos. 37507 and 38429 in Docket No. 2018-0088, the Companies may seek PIM rewards in the relevant PBR Revenue Report filing."

As described above, the PIM incentivized the increased acquisition of grid services. The Companies view continued growth in DER enrollment and capability, especially the need to increase the overall magnitude of DER grid services, as critical to furthering the effectiveness of grid services.[100] In this context, the Companies appreciate that the Commission included a DER acquisition PIM in the initial PBR Framework.

The Companies note that customer enrollment is not entirely within the Companies' control. While the Companies may increase spending in marketing and communications to increase enrollment (including GSPA enrollment), and increase efficiency in processing applications, the Companies are not the critical interface with customers and customers' decisions to enroll depend on customer financing and the contractors' ability to explain grid service program offerings.

The interim Grid Services PIM expired on December 31, 2023, and no successor mechanism has been approved. In D&O 37507, the Commission signaled that the PIM was intended to be interim in nature, and that the Commission intended to replace the interim PIM with a more sophisticated PIM that would incent utilization of grid services from DERs.[101] In subsequent Commission orders, the replacement PIM has been referred to as the "Long-Term Grid Services PIM" or "Long-Term DER Utilization PIM." In D&O 38429, the Commission instructed the PBR Working Group to focus on developing proposals for the Long-Term Grid Services PIM by July 2023, and on July 3, 2023, the Companies and the DER Parties both submitted proposals for a Long-Term Grid Service PIM. On July 10, 2023, several parties

[100] In Ulupono Initiative LLC's Phase 3 Post-Hearing Brief, filed May 11, 2022, at 29, and Hawaiian Electric Companies' Post Hearing Reply Brief, filed May 25, 2022, at 17, the Companies and Ulupono discussed the importance of increasing the overall magnitude of DER grid services. During the Panel Hearing held on April 27, 2022, Hawaiian Electric witness Mr. Kawanami stated: "we want to see the day we can achieve a substantial amount of DER" and "utilization will naturally follow the moment we can achieve a high number of capability." Yoh Kawanami, Panel Hearing Day 2, at 02:51:41 - 02:52:13.
[101] *See* D&O 37507 at 106.

submitted a proposed stipulated procedural schedule to review the Companies' and the DER Parties' Long-Term Grid Service PIM proposals. However, on August 4, 2023, the Commission issued Order No. 40143, clarifying that it would address the parties' proposals according to its own schedule and tolled the stipulating parties' proposed procedural deadlines.[102] On December 26, 2023, the Commission issued Order No. 40462, clarifying that the interim Grid Service PIM shall sunset at the end of 2023, and that review and development of the Long-Term DER Utilization PIM would continue into 2024 as part of a broader examination of performance mechanisms that addresses barriers to the utilization of DERs in a comprehensive manner.

The current context surrounding the issue of grid services include:

- Grid services are and will continue to be a critical tool in the utility generation/reliability tool kit. The Companies need and support acquisition and utilization of additional grid services.
- As discussed above, Order No. 40143 tolled the stipulating parties' proposed procedural deadlines to review the Companies' and the DER Parties' Long Term Grid Service PIM proposals.
- A dispatchable grid services program is currently under discussion phase within the CER Docket No. 2019-0323.
- The Commission's "Implementation of Executive Order No. 25-01" timeline and the Commission's 2024 Inclinations both call for 400 MW of additional renewable DER capacity to be installed by 2030.
- Some of the PBR parties, in particular, Ulupono Initiative ("Ulupono"), have discussed the importance of increasing the overall magnitude of DER grid services. In Ulupono's Phase 3 Post-Hearing Brief, filed May 11, 2022, at 29, Ulupono stated "the issue of increasing grid services is more important than the issue of how best to utilize the resources."

In light of the above context, the Companies recommend the development and examination of a successor PIM during Phase 6 focusing on increased acquisition of cost-effective DER and the postponement of PIMs specifically focused on grid services utilization to a later time. This will allow for the development of the new grid services program

[102] *See* Order No. 40143 at 2-3.

currently in discussion in Docket No. 2019-0323, and will allow the Companies to propose a PIM based on available programs that are more broadly "CER" resources rather than resources that are constrained to grid service programs. The Companies' position is that a successor PIM should more broadly include other customer-sited resources in order to incent more expansive growth, rather than be constrained to grid service programs with battery participation.

Q. RPS-A PIM

The Companies' experience with the RPS-A PIM during MRP1 has been mixed. The PIM provided an incentive to accelerate renewable portfolio standard ("RPS") achievement and the Companies modestly exceeded the RPS-A target in 2021, 2023, and 2024, earning rewards of $1,030,000, $444,000, and $1,889,000, respectively, while continuing to exceed the statutory RPS requirement of 30%. However, as previously discussed in this proceeding, the intended benefits of the RPS-A PIM have not been realized due to events outside of the Companies' control (*i.e.*, Force Majeure claims) that persist to this day, the COVID-19 Pandemic, Global supply chain issues and the European Conflict. The negative impact of these exogenous events on the Companies' RPS-A achievement was compounded by a declining $/MWh RPS-A award rate through the MRP that further depressed the RPS-A PIM reward that the Companies could earn. The RPS-A PIM addresses all three of the Commission's guiding principles by:

- Utilizing a customer-centric approach
    - Reduces exposure to fuel price and bill volatility through accelerated RPS achievement
- Increasing administrative efficiency
    - The RPS-A PIM incentivizes accelerated compliance with RPS law and in doing so, achieves many of the goals and priority outcomes of the PBR process.
- Improves utility financial integrity
    - Provides a financial incentive for adding renewable projects that increase RPS, which has predominantly been IPP projects that the utility does not earn a return on.

Thus, the Companies favor continuation of this PIM, but potential modifications should be considered to restore its intended significant reward potential and to ensure that the means of achievement are more within the Companies' reasonable control.

R. LMI Energy Efficiency PIM

The Companies earned modest rewards of $454,000 and $11,000 under the first two years of this PIM and are currently pending Hawaiʻi Energy's verified results from the third year of the PIM during MRP1. The Companies supported the intent and objective of this PIM, but it had some design deficiencies. The initial evaluation year for this PIM was the period July 1, 2021 through June 30, 2022. The LMI Energy Efficiency PIM was set for three (3) years, after which the metrics, targets, and incentives would be re-evaluated. The activities that the Companies undertook in furtherance of this PIM are further discussed in the Companies' PUC-HECO-IR-110 filed on December 5, 2023 in Docket No. 2018-0088.

It was often difficult for the Companies to determine in a timely manner what performance was required to earn a reward (*i.e.*, to exceed Hawaiʻi Energy's targets) during the actual performance period for this PIM. Because the Companies are only allowed to recover a reward on this PIM if Hawaiʻi Energy exceeds its targets, performance on this PIM is predominantly outside the control of the Companies.

In addition, there is a substantial lag between the evaluation year and the time when the Companies may begin recovery of a PIM reward. The LMI Energy Efficiency PIM requires verified results for Hawaiʻi Energy's performance year, which adds about a year lag between the end of the performance year and the start of recovery of the PIM reward.

Hawai‘i Energy Performance Year	Verified Results Filed	PIM Reward Recovery Starting
July 1, 2021-June 30, 2022	March 2, 2023	June 1, 2023
July 1, 2022-June 30, 2023	April 5, 2024	June 1, 2024
July 1, 2023-June 30, 2024	TBD	TBD

As stated in Order No. 38769 issued on December 16, 2022, in Transmittal No. 22-03 at 12-13:

> That being said, the Commission acknowledges some of the considerations implicated by the Companies' request. The Commission recognizes, for example, that the Companies' ability to utilize verified energy savings is dependent on the verification process for Hawaii Energy that is overseen by the Commission. The Commission will investigate whether steps can be taken to help expedite the verification process, which could help reduce lag for claiming performance incentives for both the Companies and Hawaii Energy. Additionally, the Commission recognizes that given the biannual nature of the Commission's review of proposed modifications to the Companies' RBA Rate Adjustment and associated impact to Target Revenues under the PBR Framework, depending on when verified results are made available, there could be a sizeable lag between the PIM's evaluation period and when any earned financial award is received.

For these reasons, the Companies plan to continue to work collaboratively with Hawai‘i Energy within the parameters of the Companies' current priorities and budget, but submits that it is not necessary to modify or continue this PIM beyond its sunset date of June 30, 2024. The Companies could support consideration of a new PIM or other programs to support LMI customers.[103]

[103] Exhibit A to Order No. 40032 issued on June 23, 2023, in Docket No. 2022-0250 at 12 states, "The Commission recommends utilizing the equity docket to strengthen the PBR framework by assessing and implementing regulatory mechanisms that will better monitor utility performance on energy equity and incentivize behavior that will result in more equitable outcomes for customers, including vulnerable populations."

S. Generation Reliability PIM

Under the first two years of this PIM during MRP1,[104] there was no penalty for any Companies in 2023 but Hawai‘i Electric Light incurred the maximum penalty for Generation SAIDI in 2024. The Commission has previously stated that this PIM "complements other PIMs in the PBR Framework that serve to incentivize the Companies to ensure that efforts to maintain service reliability are balanced with other key initiatives, such as integrating increasing amounts of renewable energy and retiring fossil fuel units."[105] The Companies do not propose any modifications to this mechanism during Phase 6.

T. Interconnection of Utility Scale Renewable Projects PIM ("IRS PIM")

Since the inception of this PIM, the Companies are now in the process of completing their first interconnection requirements studies ("IRS") under the PIM. Many of the Stage 3 projects remain ongoing. In general, the Companies have met the timelines set forth in the PIM for the Companies' performance. However, the overall timeline for the IRS has taken longer than expected due to the delay in receipt of working models and deliverables from developers, as well as developers withdrawing from group studies, requiring that such studies be restarted, and extending timelines for completion. Based on the current status of the Stage 3 IRS projects, modifications should be made to consider delays out of the Companies' control and to provide incentives to developers to provide more timely and accurate models and information. This could be achieved by creating two classifications of delays.

[104] The first evaluation period for this PIM started on January 1, 2023.
[105] D&O 38429 at 13-14.

The Companies propose to examine modifications to this mechanism during Phase 6.[106] Additionally, the IE has also recommended modifying the IRS PIM.[107]

U. Collective Shared Savings Mechanism ("CSSM")

Under the first two years of this PIM during MRP1,[108] there was no reward for any Company in 2023 and only Hawai‘i Electric Light achieved a reward in 2024, of $2.8 million. Under the CSSM, the Companies are allowed to retain a portion of any reduction in the sum of fuel, purchased power, and MPIR/EPRM costs for each future performance year in comparison to a base year. The calculation of the CSSM is based on a base year of calendar year 2021. Potentially, the base year could be modified for MRP2 to reflect 2026 or some other more recent year performance. Other than potential modification to the base year, the Companies do not propose any modifications to this mechanism during Phase 6.

V. ECRC – Target Heat Rate Mechanism

Under the target heat rate provision of the ECRC tariff, the Hawaiian Electric Companies have realized heat rate losses, and under-recovered fuel costs during MRP1.

	2021 Actual	**2022 Actual**	**2023 Actual**	**2024 Actual**
Hawaiian Electric Heat Rate gain/(loss), $000s	($519)	($16)	($4,953)	($6,632)
Hawai‘i Electric Light Heat Rate gain/(loss), $000s	($3,530)	($3,456)	($348)	$705
Maui Electric Heat Rate gain/(loss), $000s	($1,012)	($261)	($248)	($136)
Hawaiian Electric Companies' Heat Rate gain/(loss), $000s	**($5,061)**	**($3,733)**	**($5,549)**	**($6,064)**

106 *See* the Companies' Reply Statement of Position, filed on May 2, 2025, Docket No. 2024-0258, at 52.
107 *See* Public Comment, *Independent Engineer Suggestions for IGP Improvement following Stage 3 Observations* submitted on April 4, 2025, Docket No. 2024-0258.
108 The first evaluation period for this PIM started on January 1, 2023.

In Docket No. 2024-0057, the Companies sought to modify the target heat rates in the ECRC tariff.[109] In its Decision and Order No. 41442 issued on December 30, 2024 ("D&O 41442"), the Commission approved modifications to the Companies' target heat rates and deadbands effective August 1, 2024. Further consideration should be given to elimination of the ECRC tariff's target heat rate provision in light of other existing or potentially new incentives encouraging increased renewable energy generation resources on the Companies' systems. The Companies propose review of the target heat mechanism during Phase 6. This is consistent with the Commission's guidance in Decision and Order No. 41442:

> The Commission finds it reasonable to expand the ECRC heat rate deadbands around the modified target heat rates because doing so will accommodate and partially reduce the volatility and uncertainties that accompany heat rate sales. The Commission recognizes that expanding the ECRC heat rate deadbands correspondingly relaxes the ECRC heat rate incentives by allowing the Companies to recover the expense impacts of an expanded range of circumstances and utility performance at their actual expense and pass that expense through to customers without incentive adjustments. However, this docket is focused on addressing the Companies' Application to increase ECRC target heat rates in accordance with specific existing tariff provisions and is not an appropriate venue to re-evaluate or modify the provisions of the ECRC Tariffs or the incentive mechanisms the tariffs embody. <u>The Commission intends to consider amendments to maintain appropriate incentives for efficient utility system maintenance and operations, and notes that the current investigations in the Performance Based Regulation proceeding, Docket No. 2018-0088, may be one appropriate venue.</u>
>
> Several factors making it reasonable to expand the ECRC heat rate deadbands identified above are positive developments. Efficient operation of the utility systems must increasingly address extensive incorporation of variable renewable generation without curtailment, economic dispatch of available generation and BESS resources on a system level, incorporation of customer-owned resources, and adaptation of legacy utility-owned fossil generation units to accommodate substantial changes in daily load requirements. <u>These changes raise the question of whether it is accurate and effective to use generation unit heat rates as a metric to</u>

[109] The ECRC tariff provides for request of modification of target heat rates under certain conditions.

gauge, reward, or penalize the Companies for efficiency in operating the utility systems.[110]

W. ECRC – Fossil Fuel Cost Risk Sharing Mechanism

Under the fossil fuel cost risk sharing mechanism ("FFCRS") of the ECRC tariff, the Hawaiian Electric Companies have experienced mixed results during MRP1 as the cost of fuel has fluctuated.

	2021 Actual	**2022 Actual**	**2023 Actual**	**2024 Actual**
Hawaiian Electric FFCRS gain/(loss), $000s	($2,500)	($2,500)	$2,500	$1,594
Hawai'i Electric Light FFCRS gain/(loss), $000s	($398)	($595)	$45	$363
Maui Electric FFCRS gain/(loss), $000s	($626)	($633)	$232	$174
Hawaiian Electric Companies' FFCRS gain/(loss), $000s	**($3,524)**	**($3,728)**	**$2,777**	**$2,131**

Fuel price is outside of the Companies' control. Whether the Companies win or lose on this mechanism is not driven by the Companies' performance or by actions taken by the Companies. While HRS 269-16(g) requires some risk sharing relating to fuel cost changes, a mechanism that does not allow behavioral or other change within the Companies' reasonable control to alter mechanism outcomes is inconsistent with PBR principles; thus, consideration should be given to an alternative mechanism or a reduction in amounts at risk in light of other existing incentives for the Companies to replace fossil fuel generation with renewable generation.

A change or substitute for this mechanism should be considered in Phase 6. This mechanism exposes the Companies and customers to financial volatility for a portion of the

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110 D&O 41442 at 46-48 (emphasis added).

fossil fuel generation costs for the year relative to what the fuel costs would have been using January fuel prices of that calendar year, subject to a cap, for which the Companies do not have reasonable control to manage the mechanism outcomes.

IV. Conclusion

The Hawaiian Electric Companies appreciate this opportunity to provide their comments on how the Companies have been able to perform under the PBR Framework during MRP1, how such performance has matched up with the Framework's goals and outcomes, and which specific performance mechanisms should be examined during Phase 6 for potential modification.

The PBR Framework had somewhat mixed results in promoting priority outcomes during MRP1. Although the Companies realized significant achievements in certain areas, select changes to the Framework would improve support for more broadly obtaining desired results. The Companies' view is that the PBR Working Group should center its efforts on a smaller number of potential Framework changes that will have meaningful impacts as is discussed above.

The Companies look forward to the Commission's guidance addressing Phase 5 and the discussion of next steps towards transitioning to Phase 6.

DATED: Honolulu, Hawai‘i, May 5, 2025.

/s/ Rod S. Aoki
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HAWAI‘I ELECTRIC LIGHT COMPANY, INC.
MAUI ELECTRIC COMPANY, LIMITED

HAWAIIAN ELECTRIC COMPANIES
Evaluation of I-Factor in Compounded Portion of ARA

PURPOSE:
The purpose of this analysis is to evaluate if target revenues derived from an I-Factor were sufficient to keep up with actual inflations during MRP1 (6/1/2021-5/31/2026) as described in Decision and Order No. 37507 at 30-31:

> [T]he PBR Framework established a multi-year rate period ("MRP") of five years, during which Hawaiian Electric's annual target revenues will be primarily derived from the application of a formula consisting of the following factors: (1) **an inflation factor ("I-Factor"), to allow revenues to keep pace with inflation**; (2) a pre-determined annual productivity factor ("X-Factor"); (3) an exogenous events factor to allow the Companies to seek cost recovery for events outside of Hawaiian Electric's control that result in a severe impact ("Z-Factor"); and (4) a stretch factor intended to share with customers the benefits and cost savings expected to accrue to the utility under the PBR Framework ("Customer Dividend" or "CD"). Collectively, these four factors comprise the Annual Revenue Adjustment mechanism ("ARA") which will provide for annual adjustments to Hawaiian Electric's target revenue during the MRP.

ANALYSIS:
Compare the compounded portion of the ARA for MRP1 calculated using:
(i) forecasted annual percentage change from prior year in GDPPI ("GDPPI") for the I-Factor (pages 3-4); and
(ii) actual GDPPI for the I-Factor (pages 5-6).

The compounded portion of the ARA (I-Factor, X-Factor, Multiplicative CD-Factor, and prior years' compounded portions of the ARA), not I-Factor revenues, were reviewed and evaluated the I-Factor in this analysis. This is because an I-Factor revenue for "current" year will be included in "Basis for Compounded Portion of the ARA Adjustment" to calculate I-Factor, X-Factor and Multiplicative CD-Factor revenues for the subsequent years. That is, any (deficiency)/surplus in revenues derived from the I-Factor for the "current" year will affect I-Factor and Multiplicative CD-Factor revenues for the remaining years of MRP1.

ASSUMPTIONS/NOTE:
- The GDPPI is set at 2.2% for 2025 (based on Blue Chip's October forecast) and at 2.0% for 2026 (based on the long-term Federal Reserve inflation target), consistent with the assumptions used for the Companies' financial analysis, which was provided in Exhibit 4 to the Companies' Brief ("Rebasing Brief") filed on December 5, 2024.
- All inputs other than GDPPI are known.

CONCLUSION:
The summary of the revenue (deficiency)/surplus, including and excluding revenue taxes (pages 2-3) shows that the compounded portions of the ARA (I-Factor, X-Factor, Multiplicative CD-Factor, and prior years' compounded portions of the ARA) calculated using the forecasted GDPPI in the approved 2021 Annual Decoupling filing and 2021-2023 Fall Revenue Reports were not sufficient to keep pace with the actual GDPPI over that same period. Because the forecasted GDPPI used in the ARA calculation for Year 1 and Year 2 of MRP1 (i.e., 2021 and 2022) was significantly lower than the actual GDPPI for those years, the deficiencies in revenues derived from an I-Factor for those years have been compounded in the ARA calculation. Through the end of December 2024, the cumulative revenue deficiency derived from the I-Factor and the resulting impact of the customer dividend amounted to $233.1 million, including revenue taxes, for the consolidated Companies (HE: $156.9 million, HL: $38.5 million, ME: $37.7 million). The cumulative revenue deficiency, including revenue taxes, is estimated at $384.9 million (HE: $259.0 million, HL: $63.6 million, ME: $62.2 million) through May 2026 (the end of MRP1), assuming the GDPPI of 2.2% for 2025 and 2.0% for 2026.

HAWAIIAN ELECTRIC COMPANIES
Summary of Revenue (Deficiency)/Surplus (including Revenue Taxes)

1. Annual % Change from Prior Year in GDPPI

	2021 Decoupling	2022 Fall	2023 Fall	2024 Fall	2025 Fall	2026 Fall	Avg GDPPI % Change	
Annual % Change from Prior Year in GDPPI	2021	2022	2023	2024	2025	2026	2021-2023	2021-2024
Forecast (Note 1)	1.90%	3.00%	3.90%	2.40%	2.20%	2.00%	2.93%	2.80%
Actual (Note 2)	4.50%	7.10%	3.60%	2.40%	2.20%	2.00%	5.07%	
(Under) / Over-Forecasted	-2.60%	-4.10%	0.30%	0.00%	0.00%	0.00%	-2.13%	

2. Compounded Portion of ARA (Current & Prior Years), incl. revenue taxes ($ in thousands)

	MRP1 (6/1/21 to 5/31/26)							INTERIM	Total	MRP1	
	6/1/21 to 12/31/21	2022	2023	2024	2025	1/1/26 to 5/31/26	MRP1 Total	6/1/26 to 12/31/26	2026 (1/1-12/31)	+ Interim	
HAWAIIAN ELECTRIC											
Compounded Portion of ARA (Current & Prior Years)											
Based on Forecast GDPPI % Change	$ 6,911	$ 31,619	$ 58,602	$ 75,174	$ 90,555	$ 43,297	$ 306,158	$ 61,359	$ 104,656	$ 367,517	(page 3)
Based on Actual GDPPI % Change	$ 17,606	$ 80,365	$ 106,797	$ 124,421	$ 140,776	$ 64,785	$ 534,749	$ 91,810	$ 156,594	$ 626,559	(page 6)
Target Revenue (Deficiency)/Surplus	$ (10,695)	$ (48,746)	$ (48,195)	$ (49,247)	$ (50,221)	$ (21,488)	$ (228,591)	$ (30,451)	$ (51,939)	$ (259,043)	
Cumulative Target Revenue (Deficiency)/Surplus	$ (10,695)	$ (59,441)	$ (107,636)	**$ (156,883)**	$ (207,104)	$ (228,591)		**$ (259,043)**			
HAWAII ELECTRIC LIGHT											
Compounded Portion of ARA (Current & Prior Years)											
Based on Forecast GDPPI % Change	$ 1,697	$ 7,764	$ 14,388	$ 18,457	$ 22,233	$ 10,630	$ 75,170	$ 15,065	$ 25,695	$ 90,234	(page 3)
Based on Actual GDPPI % Change	$ 4,323	$ 19,732	$ 26,222	$ 30,548	$ 34,563	$ 15,906	$ 131,294	$ 22,542	$ 38,448	$ 153,836	(page 6)
Target Revenue (Deficiency)/Surplus	$ (2,626)	$ (11,968)	$ (11,833)	$ (12,091)	$ (12,329)	$ (5,276)	$ (56,125)	$ (7,477)	$ (12,753)	$ (63,602)	
Cumulative Target Revenue (Deficiency)/Surplus	$ (2,626)	$ (14,594)	$ (26,428)	**$ (38,519)**	$ (50,849)	$ (56,125)		**$ (63,602)**			
MAUI ELECTRIC											
Compounded Portion of ARA (Current & Prior Years)											
Based on Forecast GDPPI % Change	$ 1,659	$ 7,594	$ 14,075	$ 18,055	$ 21,749	$ 10,399	$ 73,532	$ 14,737	$ 25,136	$ 88,269	(page 4)
Based on Actual GDPPI % Change	$ 4,228	$ 19,302	$ 25,650	$ 29,883	$ 33,811	$ 15,559	$ 128,433	$ 22,049	$ 37,609	$ 150,483	(page 7)
Target Revenue (Deficiency)/Surplus	$ (2,569)	$ (11,708)	$ (11,575)	$ (11,828)	$ (12,062)	$ (5,160)	$ (54,902)	$ (7,312)	$ (12,472)	$ (62,214)	
Cumulative Target Revenue (Deficiency)/Surplus	$ (2,569)	$ (14,277)	$ (25,852)	**$ (37,680)**	$ (49,742)	$ (54,902)		**$ (62,214)**			
CONSOLIDATED											
Compounded Portion of ARA (Current & Prior Years)											
Based on Forecast GDPPI % Change	$ 10,267	$ 46,977	$ 87,065	$ 111,686	$ 134,538	$ 64,327	$ 454,859	$ 91,160	$ 155,487	$ 546,020	(page 4)
Based on Actual GDPPI % Change	$ 26,157	$ 119,400	$ 158,669	$ 184,852	$ 209,150	$ 96,250	$ 794,477	$ 136,401	$ 232,651	$ 930,878	(page 7)
Target Revenue (Deficiency)/Surplus	$ (15,890)	$ (72,423)	$ (71,604)	$ (73,166)	$ (74,612)	$ (31,924)	$ (339,618)	$ (45,240)	$ (77,164)	$ (384,858)	
Cumulative Target Revenue (Deficiency)/Surplus	$ (15,890)	$ (88,312)	$ (159,916)	**$ (233,082)**	$ (307,694)	$ (339,618)		**$ (384,858)**			

NOTES:
1 - [2021-2025] The consensus projection of annual percentage change in GDPPI for the Adjustment Year published by the Blue Chip Economic Indicators (Aspen Publishing) each October preceding the Adjustment Year. See each Company's WP-C-001 included in the Fall and Spring Revenue Reports for the respective adjustment years.
2 - [2021-2024] Bureau of Economic Analysis ("BEA"), U.S. Department of Commerce, National Data, National Income and Product Accounts, Interactive Data, Table 1.1.7 Percent Change From Preceding Period in Prices for Gross Domestic Product, which is available at:
https://apps.bea.gov/iTable/?reqid=19&step=3&isuri=1&1921=survey&1903=11&_gl=1*pb3vae*_ga*OTI4NTYxNTYyLjE3MjM2ODUxMjI.*_ga_J4698JNNFT*MTcyMzY4NTEyMS4xLjEuMTcyMzY4NTM3OS42MC4wLjA.#eyJhcHBpZCI6MTksInN0ZXBzIjpbMSwyLDMsM10sImRhdGEiOltbIk5JUEFfVGFibGVfTGlzdCIsIjExIl0sWyJDYXRlZ29yaWVzIiwiU3VydmV5Il0sWyJGaXJzdF9ZZWFyIiwiMjAyMCJdLFsiTGFzdF9ZZWFyIiwiMjAyNCJdLFsiU2NhbGUiLCIwIl0sWyJTZXJpZXMiLCJBIl1dfQ==
3 - Actual GDPPI for 2021 has been revised from 4.6% to 4.5% on the BEA website.
4 - Blue indicates assumptions made in calculations or amounts derived based on the assumptions.

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Summary of Revenue (Deficiency)/Surplus (excluding Revenue Taxes)

1. Annual % Change from Prior Year in GDPPI

	2021 Decoupling	2021 Fall	2022 Fall	2023 Fall	2024 Fall	2025 Fall	Avg GDPPI % Change	
Annual % Change from Prior Year in GDPPI	2021	2022	2023	2024	2025	2026	2021-2023	2021-2024
Forecast (Note 1)	1.90%	3.00%	3.90%	2.40%	2.20%	2.00%	2.93%	2.80%
Actual (Note 2)	4.60%	7.10%	3.60%	2.40%	2.20%	2.00%	5.10%	
(Under) / Over-Forecasted	-2.70%	-4.10%	0.30%	0.00%	0.00%	0.00%	-2.17%	

2. Compounded Portion of ARA (Current & Prior Years), excl. revenue taxes ($ in thousands)

	MRP1 (6/1/21 to 5/31/26)							INTERIM	Total	MRP1	
	6/1/21 to 12/31/21	2022	2023	2024	2025	1/1/26 to 5/31/26	MRP1 Total	6/1/26 to 12/31/26	2026 (1/1-12/31)	+ Interim	
HAWAIIAN ELECTRIC											
Compounded Portion of ARA (Current & Prior Years)											
Based on Forecast GDPPI % Change	$ 6,297	$ 28,810	$ 53,395	$ 68,495	$ 82,509	$ 39,450	$ 278,956	$ 55,907	$ 95,357	$ 334,863	(page 2)
Based on Actual GDPPI % Change	$ 16,041	$ 73,225	$ 97,308	$ 113,366	$ 128,268	$ 59,029	$ 487,237	$ 83,652	$ 142,681	$ 570,889	(page 5)
Target Revenue (Deficiency)/Surplus	$ (9,745)	$ (44,415)	$ (43,913)	$ (44,871)	$ (45,759)	$ (19,578)	$ (208,281)	$ (27,746)	$ (47,324)	$ (236,027)	
Cumulative Target Revenue (Deficiency)/Surplus	$ (9,745)	$ (54,160)	$ (98,073)	$ (142,944)	$ (188,703)	$ (208,281)		$ (236,027)			
HAWAII ELECTRIC LIGHT											
Compounded Portion of ARA (Current & Prior Years)											
Based on Forecast GDPPI % Change	$ 1,546	$ 7,074	$ 13,110	$ 16,817	$ 20,258	$ 9,686	$ 68,491	$ 13,726	$ 23,412	$ 82,217	(page 2)
Based on Actual GDPPI % Change	$ 3,939	$ 17,979	$ 23,892	$ 27,834	$ 31,492	$ 14,493	$ 119,629	$ 20,539	$ 35,032	$ 140,168	(page 5)
Target Revenue (Deficiency)/Surplus	$ (2,393)	$ (10,905)	$ (10,782)	$ (11,017)	$ (11,234)	$ (4,807)	$ (51,138)	$ (6,813)	$ (11,620)	$ (57,951)	
Cumulative Target Revenue (Deficiency)/Surplus	$ (2,393)	$ (13,298)	$ (24,080)	$ (35,097)	$ (46,331)	$ (51,138)		$ (57,951)			
MAUI ELECTRIC											
Compounded Portion of ARA (Current & Prior Years)											
Based on Forecast GDPPI % Change	$ 1,512	$ 6,919	$ 12,824	$ 16,451	$ 19,817	$ 9,475	$ 66,998	$ 13,428	$ 22,903	$ 80,426	(page 3)
Based on Actual GDPPI % Change	$ 3,853	$ 17,587	$ 23,371	$ 27,228	$ 30,807	$ 14,177	$ 117,022	$ 20,090	$ 34,267	$ 137,113	(page 6)
Target Revenue (Deficiency)/Surplus	$ (2,340)	$ (10,668)	$ (10,547)	$ (10,777)	$ (10,990)	$ (4,701)	$ (50,024)	$ (6,663)	$ (11,364)	$ (56,686)	
Cumulative Target Revenue (Deficiency)/Surplus	$ (2,340)	$ (13,008)	$ (23,555)	$ (34,332)	$ (45,322)	$ (50,024)		$ (56,686)			
CONSOLIDATED											
Compounded Portion of ARA (Current & Prior Years)											
Based on Forecast GDPPI % Change	$ 9,355	$ 42,803	$ 79,329	$ 101,763	$ 122,584	$ 58,611	$ 414,445	$ 83,061	$ 141,672	$ 497,506	(page 3)
Based on Actual GDPPI % Change	$ 23,833	$ 108,791	$ 144,571	$ 168,428	$ 190,567	$ 87,698	$ 723,888	$ 124,282	$ 211,980	$ 848,170	(page 6)
Target Revenue (Deficiency)/Surplus	$ (14,478)	$ (65,988)	$ (65,242)	$ (66,665)	$ (67,983)	$ (29,087)	$ (309,443)	$ (41,221)	$ (70,308)	$ (350,664)	
Cumulative Target Revenue (Deficiency)/Surplus	$ (14,478)	$ (80,466)	$ (145,708)	$ (212,373)	$ (280,356)	$ (309,443)		$ (350,664)			

NOTES:

1 - [2021-2025] The consensus projection of annual percentage change in GDPPI for the Adjustment Year published by the Blue Chip Economic Indicators (Aspen Publishing) each October preceding the Adjustment Year. See each Company's WP-C-001 included in the 2021 Decoupling filing and Fall Revenue Reports for the respective adjustment years.

2 - [2021-2024] Bureau of Economic Analysis ("BEA"), U.S. Department of Commerce, National Data, National Income and Product Accounts, Interactive Data, Table 1.1.7 Percent Change From Preceding Period in Prices for Gross Domestic Product, which is available at:
https://apps.bea.gov/iTable/?reqid=19&step=3&isuri=1&1921=survey&1903=11&_gl=1*pb3vae*_ga*OTI4NTYxNTYyLjE3MjM2ODUxMjI.*_ga_J4698JNNFT*MTcyMzY4NTEyMS4xLjEuMTcyMzY4NTM3OS42MC4wLjA.#eyJhcHBpZCI6MTksInN0ZXBzIjpbMSwyLDMsM10sImRhdGEiOltbIk5JUEFfVGFibGVfTGlzdCIsIjExIl0sWyJDYXRlZ29yaWVzIiwiU3VydmV5Il0sWyJGaXJzdF9ZZWFyIiwiMjAyMCJdLFsiTGFzdF9ZZWFyIiwiMjAyNCJdLFsiU2NhbGUiLCIwIl0sWyJTZXJpZXMiLCJBIl1dfQ==

3 - Actual GDPPI for 2021 has been revised from 4.6% to 4.5% on the BEA website.

4 - Blue indicates assumptions made in calculations or amounts derived based on the assumptions

HAWAIIAN ELECTRIC COMPANIES

Compounded Portion of ARA (I-Factor Based on Forecast GDPPI Growth Rate)

($ In Thousands)

	MRP1 (6/1/21 to 5/31/26)						INTERIM	Total
	6/1/21 to 12/31/21	2022	2023	2024	2025	1/1/26 to 5/31/26	6/1/26 to 12/31/26	2026 (1/1-12/31)
I-Factor (Forecast GDPPI Growth Rate) (Sch C, WP-C-001)	1.90%	3.00%	3.90%	2.40%	2.20%			2.00%
X-Factor (Sch C)	0.00%	0.00%	0.00%	0.00%	0.00%			0.00%
Multiplicative CD-Factor (Sch C)	-0.22%	-0.22%	-0.22%	-0.22%	-0.22%			-0.22%
Revenue Tax Factor	1.097514	1.097514	1.097514	1.097514	1.097514	1.097514	1.097514	1.097514
HAWAIIAN ELECTRIC								
Basis for Compd Portion of ARA Adj. (Sch C, C1)	$ 639,273	$ 650,013	$ 668,083	$ 692,668	$ 707,768			$ 721,782
I-Factor (Forecast GDPPI Growth Rate) (Sch C)	$ 12,146	$ 19,500	$ 26,055	$ 16,624	$ 15,571			$ 14,436
X-Factor (Sch C)	$ -	$ -	$ -	$ -	$ -			$ -
Multiplicative CD-Factor (Sch C)	$ (1,406)	$ (1,430)	$ (1,470)	$ (1,524)	$ (1,557)			$ (1,588)
Compd Portion of ARA Adj. (Sch B1)	$ 10,740	$ 18,070	$ 24,585	$ 15,100	$ 14,014			$ 12,848
Compd Portion of ARA Adj. incl. rev. taxes (Sch B1, C)	$ 11,787	$ 19,832	$ 26,982	$ 16,572	$ 15,381			$ 14,101
Accrued Target Revenue: Compd Portion of ARA Adj.								
Current Year ("CY")	$ 10,740							
Distribution % for Jun-Dec 2021	58.63%							
Current Year (Sch A1 for 2021, Sch B1)	$ 6,297	$ 18,070	$ 24,585	$ 15,100	$ 14,014	$ 5,315	$ 7,533	$ 12,848
Prior Years ("PYs")								
2021		$ 10,740	$ 10,740	$ 10,740	$ 10,740	$ 4,443	$ 6,297	$ 10,740
2022			$ 18,070	$ 18,070	$ 18,070	$ 7,476	$ 10,594	$ 18,070
2023				$ 24,585	$ 24,585	$ 10,171	$ 14,414	$ 24,585
2024					$ 15,100	$ 6,247	$ 8,853	$ 15,100
2025						$ 5,798	$ 8,216	$ 14,014
Total PYs (Sch C1)	$ -	$ 10,740	$ 28,810	$ 53,395	$ 68,495	$ 34,135	$ 48,374	$ 82,509
Total CY & PYs (excl. rev. taxes) (Sch A1 or B1 Ln 11-15)	$ 6,297	$ 28,810	$ 53,395	$ 68,495	$ 82,509	$ 39,450	$ 55,907	$ 95,357
Total CY & PYs (incl. rev. taxes) (Sch A Ln 5a or 5-6a)	$ 6,911	$ 31,619	$ 58,602	$ 75,174	$ 90,555	$ 43,297	$ 61,359	$ 104,656
Cumulative Total CY & PYs (excl. rev. taxes)	$ 6,297	$ 35,107	$ 88,502	$ 156,997	$ 239,506	$ 278,956	$ 334,863	$ 334,863
Cumulative Total CY & PYs (incl. rev. taxes)	$ 6,911	$ 38,530	$ 97,132	$ 172,306	$ 262,861	$ 306,158	$ 367,517	$ 367,517
HAWAII ELECTRIC LIGHT								
Basis for Compd Portion of ARA Adj. (Sch C, C1)	$ 156,952	$ 159,589	$ 164,026	$ 170,062	$ 173,769			$ 177,210
I-Factor (Forecast GDPPI Growth Rate) (Sch C)	$ 2,982	$ 4,788	$ 6,397	$ 4,081	$ 3,823			$ 3,544
X-Factor (Sch C)	$ -	$ -	$ -	$ -	$ -			$ -
Multiplicative CD-Factor (Sch C)	$ (345)	$ (351)	$ (361)	$ (374)	$ (382)			$ (390)
Compd Portion of ARA Adj. (Sch B1)	$ 2,637	$ 4,437	$ 6,036	$ 3,707	$ 3,441			$ 3,154
Compd Portion of ARA Adj. incl. rev. taxes (Sch B1, C)	$ 2,894	$ 4,870	$ 6,625	$ 4,068	$ 3,777			$ 3,462
Accrued Target Revenue: Compd Portion of ARA Adj.								
Current Year ("CY")	$ 2,637							
Distribution % for Jun-Dec 2021	58.63%							
Current Year (Sch A1 for 2021, Sch B1)	$ 1,546	$ 4,437	$ 6,036	$ 3,707	$ 3,441	$ 1,305	$ 1,849	$ 3,154
Prior Years ("PYs")								
2021		$ 2,637	$ 2,637	$ 2,637	$ 2,637	$ 1,091	$ 1,546	$ 2,637
2022			$ 4,437	$ 4,437	$ 4,437	$ 1,836	$ 2,601	$ 4,437
2023				$ 6,036	$ 6,036	$ 2,497	$ 3,539	$ 6,036
2024					$ 3,707	$ 1,534	$ 2,173	$ 3,707
2025						$ 1,424	$ 2,017	$ 3,441
Total PYs (Sch C1)	$ -	$ 2,637	$ 7,074	$ 13,110	$ 16,817	$ 8,381	$ 11,877	$ 20,258
Total CY & PYs (excl. rev. taxes) (Sch A1 or B1 Ln 11-15)	$ 1,546	$ 7,074	$ 13,110	$ 16,817	$ 20,258	$ 9,686	$ 13,726	$ 23,412
Total CY & PYs (incl. rev. taxes) (Sch A Ln 5a or 5-6a)	$ 1,697	$ 7,764	$ 14,388	$ 18,457	$ 22,233	$ 10,630	$ 15,065	$ 25,695
Cumulative Total CY & PYs (excl. rev. taxes)	$ 1,546	$ 8,620	$ 21,730	$ 38,547	$ 58,805	$ 68,491	$ 82,217	$ 82,217
Cumulative Total CY & PYs (incl. rev. taxes)	$ 1,697	$ 9,461	$ 23,849	$ 42,306	$ 64,539	$ 75,170	$ 90,234	$ 90,234

	MRP1 (6/1/21 to 5/31/26)						INTERIM	Total
	6/1/21 to 12/31/21	2022	2023	2024	2025	1/1/26 to 5/31/26	6/1/26 to 12/31/26	2026 (1/1-12/31)
I-Factor (Forecast GDPPI Growth Rate) (Sch C, WP-C-001)	1.90%	3.00%	3.90%	2.40%	2.20%			2.00%
X-Factor (Sch C)	0.00%	0.00%	0.00%	0.00%	0.00%			0.00%
Multiplicative CD-Factor (Sch C)	-0.22%	-0.22%	-0.22%	-0.22%	-0.22%			-0.22%
Revenue Tax Factor	1.097514	1.097514	1.097514	1.097514	1.097514	1.097514	1.097514	1.097514
MAUI ELECTRIC								
Basis for Compd Portion of ARA Adj. (Sch C, C1)	$ 153,537	$ 156,116	$ 160,456	$ 166,361	$ 169,988			$ 173,354
I-Factor (Forecast GDPPI Growth Rate) (Sch C)	$ 2,917	$ 4,683	$ 6,258	$ 3,993	$ 3,740			$ 3,467
X-Factor (Sch C)	$ -	$ -	$ -	$ -	$ -			$ -
Multiplicative CD-Factor (Sch C)	$ (338)	$ (343)	$ (353)	$ (366)	$ (374)			$ (381)
Compd Portion of ARA Adj. (Sch B1)	$ 2,579	$ 4,340	$ 5,905	$ 3,627	$ 3,366			$ 3,086
Compd Portion of ARA Adj. incl. rev. taxes (Sch B1, C)	$ 2,830	$ 4,763	$ 6,481	$ 3,981	$ 3,694			$ 3,387
Accrued Target Revenue: Compd Portion of ARA Adj.								
Current Year ("CY")	$ 2,579							
Distribution % for Jun-Dec 2021	58.63%							
Current Year (Sch A1 for 2021, Sch B1)	$ 1,512	$ 4,340	$ 5,905	$ 3,627	$ 3,366	$ 1,277	$ 1,809	$ 3,086
Prior Years ("PYs")								
2021		$ 2,579	$ 2,579	$ 2,579	$ 2,579	$ 1,067	$ 1,512	$ 2,579
2022			$ 4,340	$ 4,340	$ 4,340	$ 1,796	$ 2,544	$ 4,340
2023				$ 5,905	$ 5,905	$ 2,443	$ 3,462	$ 5,905
2024					$ 3,627	$ 1,501	$ 2,126	$ 3,627
2025						$ 1,393	$ 1,973	$ 3,366
Total PYs (Sch C1)	$ -	$ 2,579	$ 6,919	$ 12,824	$ 16,451	$ 8,198	$ 11,619	$ 19,817
Total CY & PYs (excl. rev. taxes) (Sch A1 or B1 Ln 11-15)	$ 1,512	$ 6,919	$ 12,824	$ 16,451	$ 19,817	$ 9,475	$ 13,428	$ 22,903
Total CY & PYs (incl. rev. taxes) (Sch A Ln 5a or 5-6a)	$ 1,659	$ 7,594	$ 14,075	$ 18,055	$ 21,749	$ 10,399	$ 14,737	$ 25,136
Cumulative Total CY & PYs (excl. rev. taxes)	$ 1,512	$ 8,431	$ 21,255	$ 37,706	$ 57,523	$ 66,998	$ 80,426	$ 80,426
Cumulative Total CY & PYs (incl. rev. taxes)	$ 1,659	$ 9,253	$ 23,328	$ 41,383	$ 63,132	$ 73,532	$ 88,269	$ 88,269
CONSOLIDATED								
Basis for Compd Portion of ARA Adj. (Sch C, C1)	$ 949,762	$ 965,718	$ 992,565	$ 1,029,091	$ 1,051,525			$ 1,072,346
I-Factor (Forecast GDPPI Growth Rate) (Sch C)	$ 18,045	$ 28,971	$ 38,710	$ 24,698	$ 23,134			$ 21,447
X-Factor (Sch C)	$ -	$ -	$ -	$ -	$ -			$ -
Multiplicative CD-Factor (Sch C)	$ (2,089)	$ (2,124)	$ (2,184)	$ (2,264)	$ (2,313)			$ (2,359)
Compd Portion of ARA Adj. (Sch B1)	$ 15,956	$ 26,847	$ 36,526	$ 22,434	$ 20,821			$ 19,088
Compd Portion of ARA Adj. incl. rev. taxes (Sch B1, C)	$ 17,512	$ 29,465	$ 40,088	$ 24,622	$ 22,851			$ 20,949
Accrued Target Revenue: Compd Portion of ARA Adj.								
Current Year ("CY")	$ 15,956							
Distribution % for Jun-Dec 2021	58.63%							
Current Year (Sch A1 for 2021, Sch B1)	$ 9,355	$ 26,847	$ 36,526	$ 22,434	$ 20,821	$ 7,897	$ 11,191	$ 19,088
Prior Years ("PYs")								
2021		$ 15,956	$ 15,956	$ 15,956	$ 15,956	$ 6,601	$ 9,355	$ 15,956
2022			$ 26,847	$ 26,847	$ 26,847	$ 11,107	$ 15,740	$ 26,847
2023				$ 36,526	$ 36,526	$ 15,111	$ 21,415	$ 36,526
2024					$ 22,434	$ 9,281	$ 13,153	$ 22,434
2025						$ 8,614	$ 12,207	$ 20,821
Total PYs (Sch C1)	$ -	$ 15,956	$ 42,803	$ 79,329	$ 101,763	$ 50,714	$ 71,870	$ 122,584
Total CY & PYs (excl. rev. taxes) (Sch A1 or B1 Ln 11-15)	$ 9,355	$ 42,803	$ 79,329	$ 101,763	$ 122,584	$ 58,611	$ 83,061	$ 141,672
Total CY & PYs (incl. rev. taxes) (Sch A Ln 5a or 5-6a)	$ 10,267	$ 46,977	$ 87,065	$ 111,686	$ 134,538	$ 64,327	$ 91,160	$ 155,487
Cumulative Total CY & PYs (excl. rev. taxes)	$ 9,355	$ 52,158	$ 131,487	$ 233,250	$ 355,834	$ 414,445	$ 497,506	$ 497,506
Cumulative Total CY & PYs (incl. rev. taxes)	$ 10,267	$ 57,244	$ 144,309	$ 255,995	$ 390,533	$ 454,859	$ 546,020	$ 546,020

SOURCES: 2021 Annual Decoupling filing and 2021-2024 Fall Revenue Reports.
NOTE: Blue indicates assumptions made in calculations or amounts derived based on the assumptions.

HAWAIIAN ELECTRIC COMPANIES

Compounded Portion of ARA (I-Factor Based on Actual GDPPI Growth Rate)

($ In Thousands)

	MRP1 (6/1/21 to 5/31/26)						INTERIM	Total
	6/1/21 to 12/31/21	2022	2023	2024	2025	1/1/26 to 5/31/26	6/1/26 to 12/31/26	2026 (1/1-12/31)
I-Factor (Actual GDPPI Growth Rate)	4.50%	7.10%	3.60%	2.40%	2.20%			2.00%
X-Factor	0.00%	0.00%	0.00%	0.00%	0.00%			0.00%
Multiplicative CD-Factor	-0.22%	-0.22%	-0.22%	-0.22%	-0.22%			-0.22%
Revenue Tax Factor	1.097514	1.097514	1.097514	1.097514	1.097514	1.097514	1.097514	1.097514
HAWAIIAN ELECTRIC								
Basis for Compd Portion of ARA Adj. (Sch C1 for 2021)	$ 639,273	$ 666,634	$ 712,498	$ 736,581	$ 752,639			$ 767,541
I-Factor (Actual GDPPI Growth Rate)	$ 28,767	$ 47,331	$ 25,650	$ 17,678	$ 16,558			$ 15,351
X-Factor	$ -	$ -	$ -	$ -	$ -			$ -
Multiplicative CD-Factor	$ (1,406)	$ (1,467)	$ (1,567)	$ (1,620)	$ (1,656)			$ (1,689)
Compd Portion of ARA Adj.	$ 27,361	$ 45,864	$ 24,083	$ 16,058	$ 14,902			$ 13,662
Compd Portion of ARA Adj. incl. rev. taxes	$ 30,029	$ 50,336	$ 26,431	$ 17,624	$ 16,355			$ 14,994
Accrued Target Revenue: Compd Portion of ARA Adj.								
Current Year ("CY")	$ 27,361							
Distribution % for Jun-Dec 2021	58.63%							
Current Year	$ 16,041	$ 45,864	$ 24,083	$ 16,058	$ 14,902	$ 5,658	$ 8,018	$ 13,662
Prior Years ("PYs")								
2021		$ 27,361	$ 27,361	$ 27,361	$ 27,361	$ 11,584	$ 16,417	$ 27,361
2022			$ 45,864	$ 45,864	$ 45,864	$ 18,993	$ 26,915	$ 45,864
2023				$ 24,083	$ 24,083	$ 9,973	$ 14,133	$ 24,083
2024					$ 16,058	$ 6,650	$ 9,423	$ 16,058
2025						$ 6,171	$ 8,746	$ 14,902
Total Pys	$ -	$ 27,361	$ 73,225	$ 97,308	$ 113,366	$ 53,371	$ 75,634	$ 128,268
Total CY & PYs (excl. rev. taxes)	$ 16,041	$ 73,225	$ 97,308	$ 113,366	$ 128,268	$ 59,029	$ 83,652	$ 141,930
Total CY & PYs (incl. rev. taxes)	$ 17,606	$ 80,365	$ 106,797	$ 124,421	$ 140,776	$ 64,785	$ 91,810	$ 155,770
Cumulative Total CY & PYs (excl. rev. taxes)	$ 16,041	$ 89,266	$ 186,574	$ 299,940	$ 428,208	$ 487,237	$ 570,889	$ 570,138
Cumulative Total CY & PYs (incl. rev. taxes)	$ 17,606	$ 97,971	$ 204,768	$ 329,189	$ 469,965	$ 534,749	$ 626,559	$ 625,735
HAWAII ELECTRIC LIGHT								
Basis for Compd Portion of ARA Adj. (Sch C1 for 2021)	$ 156,952	$ 163,670	$ 174,931	$ 180,844	$ 184,786			$ 188,444
I-Factor (Actual GDPPI Growth Rate)	$ 7,063	$ 11,621	$ 6,298	$ 4,340	$ 4,065			$ 3,769
X-Factor	$ -	$ -	$ -	$ -	$ -			$ -
Multiplicative CD-Factor	$ (345)	$ (360)	$ (385)	$ (398)	$ (407)			$ (415)
Compd Portion of ARA Adj.	$ 6,718	$ 11,261	$ 5,913	$ 3,942	$ 3,658			$ 3,354
Compd Portion of ARA Adj. incl. rev. taxes	$ 7,373	$ 12,359	$ 6,490	$ 4,326	$ 4,015			$ 3,681
Accrued Target Revenue: Compd Portion of ARA Adj.								
Current Year ("CY")	$ 6,718							
Distribution % for Jun-Dec 2021	58.63%							
Current Year	$ 3,939	$ 11,261	$ 5,913	$ 3,942	$ 3,658	$ 1,389	$ 1,969	$ 3,354
Prior Years ("PYs")								
2021		$ 6,718	$ 6,718	$ 6,718	$ 6,718	$ 2,844	$ 4,031	$ 6,718
2022			$ 11,261	$ 11,261	$ 11,261	$ 4,663	$ 6,609	$ 11,261
2023				$ 5,913	$ 5,913	$ 2,449	$ 3,470	$ 5,913
2024					$ 3,942	$ 1,632	$ 2,314	$ 3,942
2025						$ 1,515	$ 2,147	$ 3,658
Total Pys	$ -	$ 6,718	$ 17,979	$ 23,892	$ 27,834	$ 13,104	$ 18,570	$ 31,492
Total CY & PYs (excl. rev. taxes)	$ 3,939	$ 17,979	$ 23,892	$ 27,834	$ 31,492	$ 14,493	$ 20,539	$ 34,846
Total CY & PYs (incl. rev. taxes)	$ 4,323	$ 19,732	$ 26,222	$ 30,548	$ 34,563	$ 15,906	$ 22,542	$ 38,244
Cumulative Total CY & PYs (excl. rev. taxes)	$ 3,939	$ 21,918	$ 45,810	$ 73,644	$ 105,136	$ 119,629	$ 140,168	$ 139,982
Cumulative Total CY & PYs (incl. rev. taxes)	$ 4,323	$ 24,055	$ 50,277	$ 80,825	$ 115,388	$ 131,294	$ 153,836	$ 153,632

	MRP1 (6/1/21 to 5/31/26)						INTERIM	Total
	6/1/21 to 12/31/21	2022	2023	2024	2025	1/1/26 to 5/31/26	6/1/26 to 12/31/26	2026 (1/1-12/31)
I-Factor (Actual GDPPI Growth Rate)	4.50%	7.10%	3.60%	2.40%	2.20%			2.00%
X-Factor	0.00%	0.00%	0.00%	0.00%	0.00%			0.00%
Multiplicative CD-Factor	-0.22%	-0.22%	-0.22%	-0.22%	-0.22%			-0.22%
Revenue Tax Factor	1.097514	1.097514	1.097514	1.097514	1.097514	1.097514	1.097514	1.097514
MAUI ELECTRIC								
Basis for Compd Portion of ARA Adj. (Sch C1 for 2021)	$ 153,537	$ 160,108	$ 171,124	$ 176,908	$ 180,765			$ 184,344
I-Factor (Actual GDPPI Growth Rate)	$ 6,909	$ 11,368	$ 6,160	$ 4,246	$ 3,977			$ 3,687
X-Factor	$ -	$ -	$ -	$ -	$ -			$ -
Multiplicative CD-Factor	$ (338)	$ (352)	$ (376)	$ (389)	$ (398)			$ (406)
Compd Portion of ARA Adj.	$ 6,571	$ 11,016	$ 5,784	$ 3,857	$ 3,579			$ 3,281
Compd Portion of ARA Adj. incl. rev. taxes	$ 7,212	$ 12,090	$ 6,348	$ 4,233	$ 3,928			$ 3,601
Accrued Target Revenue: Compd Portion of ARA Adj.								
Current Year ("CY")	$ 6,571							
Distribution % for Jun-Dec 2021	58.63%							
Current Year	$ 3,853	$ 11,016	$ 5,784	$ 3,857	$ 3,579	$ 1,359	$ 1,925	$ 3,281
Prior Years ("PYs")								
2021		$ 6,571	$ 6,571	$ 6,571	$ 6,571	$ 2,782	$ 3,943	$ 6,571
2022			$ 11,016	$ 11,016	$ 11,016	$ 4,562	$ 6,464	$ 11,016
2023				$ 5,784	$ 5,784	$ 2,395	$ 3,394	$ 5,784
2024					$ 3,857	$ 1,597	$ 2,263	$ 3,857
2025						$ 1,482	$ 2,101	$ 3,579
Total Pys	$ -	$ 6,571	$ 17,587	$ 23,371	$ 27,228	$ 12,818	$ 18,165	$ 30,807
Total CY & PYs (excl. rev. taxes)	$ 3,853	$ 17,587	$ 23,371	$ 27,228	$ 30,807	$ 14,177	$ 20,090	$ 34,088
Total CY & PYs (incl. rev. taxes)	$ 4,228	$ 19,302	$ 25,650	$ 29,883	$ 33,811	$ 15,559	$ 22,049	$ 37,412
Cumulative Total CY & PYs (excl. rev. taxes)	$ 3,853	$ 21,440	$ 44,811	$ 72,039	$ 102,846	$ 117,022	$ 137,113	$ 136,934
Cumulative Total CY & PYs (incl. rev. taxes)	$ 4,228	$ 23,530	$ 49,180	$ 79,063	$ 112,874	$ 128,433	$ 150,483	$ 150,286
CONSOLIDATED								
Basis for Compd Portion of ARA Adj. (Sch C1 for 2021)	$ 949,762	$ 990,412	$ 1,058,553	$ 1,094,333	$ 1,118,190			$ 1,140,329
I-Factor (Actual GDPPI Growth Rate)	$ 42,739	$ 70,320	$ 38,108	$ 26,264	$ 24,600			$ 22,807
X-Factor	$ -	$ -	$ -	$ -	$ -			$ -
Multiplicative CD-Factor	$ (2,089)	$ (2,179)	$ (2,328)	$ (2,407)	$ (2,461)			$ (2,510)
Compd Portion of ARA Adj.	$ 40,650	$ 68,141	$ 35,780	$ 23,857	$ 22,139			$ 20,297
Compd Portion of ARA Adj. incl. rev. taxes	$ 44,614	$ 74,786	$ 39,269	$ 26,183	$ 24,298			$ 22,276
Accrued Target Revenue: Compd Portion of ARA Adj.								
Current Year ("CY")	$ 40,650							
Distribution % for Jun-Dec 2021	58.63%							
Current Year	$ 23,833	$ 68,141	$ 35,780	$ 23,857	$ 22,139	$ 8,406	$ 11,912	$ 20,297
Prior Years ("PYs")								
2021		$ 40,650	$ 40,650	$ 40,650	$ 40,650	$ 17,211	$ 24,390	$ 40,650
2022			$ 68,141	$ 68,141	$ 68,141	$ 28,218	$ 39,988	$ 68,141
2023				$ 35,780	$ 35,780	$ 14,817	$ 20,997	$ 35,780
2024					$ 23,857	$ 9,879	$ 14,000	$ 23,857
2025						$ 9,169	$ 12,993	$ 22,139
Total Pys	$ -	$ 40,650	$ 108,791	$ 144,571	$ 168,428	$ 79,292	$ 112,370	$ 190,567
Total CY & PYs (excl. rev. taxes)	$ 23,833	$ 108,791	$ 144,571	$ 168,428	$ 190,567	$ 87,698	$ 124,282	$ 210,864
Total CY & PYs (incl. rev. taxes)	$ 26,157	$ 119,400	$ 158,669	$ 184,852	$ 209,150	$ 96,250	$ 136,401	$ 231,426
Cumulative Total CY & PYs (excl. rev. taxes)	$ 23,833	$ 132,624	$ 277,195	$ 445,623	$ 636,190	$ 723,888	$ 848,170	$ 847,054
Cumulative Total CY & PYs (incl. rev. taxes)	$ 26,157	$ 145,556	$ 304,225	$ 489,077	$ 698,227	$ 794,477	$ 930,878	$ 929,653

SOURCE for Basis for Compounded Portion of ARA Adjustment: Schedule C1 filed in the 2021 Annual Decoupling filing for each Company.

NOTES:

1 - Blue indicates assumptions made in calculations or amounts derived based on the assumptions.

2 - Actual GDPPI for 2021 has been revised from 4.6% to 4.5% on the BEA website.

HAWAIIAN ELECTRIC COMPANIES
Management Audit Savings Commitment

Period Recorded	Hawaiian Electric	Hawaii Electric Light	Maui Electric	Consolidated	Consolidated Total ($000)	Consolidated N/I Impact ($000)	Consolidated Rate Base ($000)	Consolidated Basis Points
6/1/21-12/31/21	$ (4,618,172)	$ (995,140)	$ (992,020)	$ (6,605,332)	$ (6,605)	$ (4,469)	$ 2,061,678	(22)
1/1/22-12/31/22	$ (4,618,172)	$ (995,140)	$ (992,020)	$ (6,605,332)	$ (6,605)	$ (4,469)	$ 2,107,895	(21)
1/1/23-12/31/23	$ (4,618,172)	$ (995,140)	$ (992,020)	$ (6,605,332)	$ (6,605)	$ (4,469)	$ 2,230,841	(20)
1/1/24-12/31/24	$ (4,618,172)	$ (995,140)	$ (992,020)	$ (6,605,332)	$ (6,605)	$ (4,469)	$ 2,236,282	(20)
1/1/25-12/31/25	$ (4,618,172)	$ (995,140)	$ (992,020)	$ (6,605,332)	$ (6,605)	$ (4,469)	(not available)	(not available)
Total	$ (23,090,860)	$ (4,975,700)	$ (4,960,100)	$ (33,026,660)	$ (33,027)	$ (22,343)		

Tax Assumptions

		Effective	
Federal Income Tax Rate	21.00%	19.74%	
State Income Tax Rate	6.40%	6.02%	
		25.75%	74.25%
Public Service Company Tax		5.89%	
PUC Fee		0.50%	
Franchise Tax		2.50%	
Composite Revenue Tax Rate		8.89%	1.0975
Operating Income Divisor		67.65%	
Net Income Factor		**0.6765**	

HAWAIIAN ELECTRIC COMPANIES
Ratemaking Equity Investment
($ in thousands)

	Hawaiian Electric	Hawaii Electric Light	Maui Electric	Total
2021	1,435,156	323,199	303,324	2,061,678
2022	1,461,602	327,043	319,250	2,107,895
2023	1,553,428	336,989	340,424	2,230,841
2024	1,546,902	343,647	345,733	2,236,282

Source: 2022-2025 Spring Revenue Report, Schedule D, line 16, for the respective Companies.

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing document, together with this Certificate of Service, were duly served on the following parties and participants, by having said copies delivered by electronic service.

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DATED: Honolulu, Hawai'i, May 5, 2025.

/s/ Ayako Yamamoto
Ayako Yamamoto
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Regulatory Affairs