BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

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

DECISION AND ORDER NO. 37507

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DECISION AND ORDER

By this Decision and Order ("D&O"),[1] the Public Utilities Commission ("Commission") establishes a Performance-Based

[1]The Parties to this proceeding are HAWAIIAN ELECTRIC COMPANY, INC. ("HECO"), HAWAII ELECTRIC LIGHT COMPANY, INC. ("HELCO"), MAUI ELECTRIC COMPANY, LIMITED ("MECO")(collectively Hawaiian Electric, HELCO, and MECO are referred to as "Hawaiian Electric" or the "Companies") and the DIVISION OF CONSUMER ADVOCACY ("Consumer Advocate"), an ex officio party, pursuant to Hawaii Revised Statutes ("HRS") § 269-51 and Hawaii Administrative Rules § 16-601-62(a).

Additionally, the Commission has granted the following entities intervenor status: CITY AND COUNTY OF HONOLULU ("C&CH"), COUNTY OF HAWAII ("COH"), BLUE PLANET FOUNDATION ("Blue Planet"), HAWAII PV COALITION ("HPVC"), HAWAII SOLAR ENERGY ASSOCIATION ("HSEA"), LIFE OF THE LAND ("LOL"), ULUPONO INITIATIVE, LLC ("Ulupono"), and DER COUNCIL OF HAWAII ("DERC") (HPVC, HSEA, and DERC are occasionally jointly referred to as the "DER Parties"). See Order No. 35542, "Admitting Intervenors and Participant and Establishing a Schedule of Proceedings," filed June 20, 2018 ("Order No. 35542"). The Commission has also granted participant status to ADVANCED ENERGY ECONOMY INSTITUTE ("AEEI"). Id.

Regulation framework ("PBR Framework") to govern Hawaiian Electric. In this D&O, the Commission describes the specific regulatory mechanisms that will comprise the PBR Framework, sets forth a schedule for finalizing tariffs to implement the PBR Framework, and discusses the post-D&O working group process that will provide for the on-going examination and development of various PBR initiatives.

Building on the work started with the early decoupling mechanisms approved in Docket No. 2008-0274, this proceeding will sustain the momentum towards transforming Hawaiian Electric into a utility of the future by implementing this PBR Framework that provides tangible rate relief to customers while providing significant earnings opportunities to Hawaiian Electric in exchange for exemplary performance.

This D&O represents the culmination of over two and a half years of dedicated, focused work by the Commission and the Parties (representing a broad spectrum of key stakeholders) to realize a transformation in the regulation of Hawaiian Electric. Consistent with the regulatory principles, goals, and outcomes

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The COUNTY OF MAUI was formerly an intervenor, but has since withdrawn from this proceeding. See Order No. 36252, "Granting the County of Maui's Motion to Withdraw," filed April 3, 2019.

identified by the Commission earlier in this proceeding,[2] the PBR Framework approved by the Commission today continues the transition away from traditional cost-of-service regulation ("COSR") and will better align Hawaiian Electric's financial incentives with customer needs and the State's policy goals. Under the PBR Framework, customers will benefit from lower utility costs and see greater integration of renewable energy resources, while the Companies will have the opportunity to improve their financial position through improved efficiencies and by earning rewards for exemplary and high-quality service in targeted areas.

At this critical juncture, the Commission would like to acknowledge the tremendous amount of time, effort, and resources devoted to this proceeding by the Parties, and the Commission expresses its appreciation for the hard work and collegial spirit exhibited throughout this proceeding. The PBR Framework adopted by this D&O has been meticulously developed over the past two and a half years, and has involved: many long hours of meetings, workshops, and conferences; preparation and review of thousands of pages of analysis, briefing, and discovery requests; and several days of panel hearings (which had to be abruptly transitioned to a virtual format, due to the sudden onset of the COVID-19

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[2]See Decision and Order No. 36326, filed May 23, 2019 ("Phase 1 D&O").

pandemic). In spite of these challenges, the Parties have maintained a collaborative approach and addressed disagreement with respect and professionalism.

The Commission would also like to extend its appreciation and recognition to its consultants from Rocky Mountain Institute, Haiku Design & Analysis, and Gridworks, whose efforts in designing and facilitating the many meetings and workshops, as well as reviewing and analyzing thousands of pages of information filed in this proceeding, have been invaluable to the Commission.

In sum, reaching this point represents a tremendous achievement and can be attributed to the dedication and commitment of all involved in this proceeding. As the Commission and Hawaiian Electric move into this new PBR Framework, the Commission is confident in its solid foundation, which has undergone rigorous review, debate, analysis, and scrutiny. While the Commission expects that the PBR Framework will continue to evolve over time, it believes that the time dedicated to this proceeding over these past years has been well-spent, and will provide firm support and guidance to future Commissions and subsequent iterations of the PBR Framework.

I.

INTRODUCTION

On October 24, 2008, the Commission opened Docket No. 2008-0274 to initiate an investigation into implementing a decoupling mechanism for Hawaiian Electric to "modify the traditional model of rate-making . . . by separating the [Companies'] revenues and profits from electricity sales."[3] Working in concert with a government-wide initiative toward promoting clean, renewable energy, the Commission focused on decoupling mechanisms as a means of "encouraging the substitution of renewable resources, distributed generation and energy efficiency for the utility's fossil fuel production . . ., while simultaneously protecting a utility's financial health from erosion as these types of programs go into effect."[4]

On August 31, 2010, the Commission issued its Final Decision & Order in Docket No. 2008-0274, in which the Commission laid the foundations for the current regulatory framework for the Companies. Among other things, the Commission established a suite of decoupling and revenue mechanisms,

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[3]In re Public Util. Comm'n, Docket No. 2008-0274, "Order Initiating Investigation," filed October 24, 2008 ("Decoupling Opening Order"), at 1.

[4]Decoupling Opening Order at 2-3.

including the Revenue Balancing Account ("RBA"), Rate Adjustment Mechanism ("RAM"), and a triennial rate case cycle, under which each of the Companies would file general rate cases on a staggered three-year cycle.[5] Representing "a transformational change from traditional rate-making[,]"[6] these new decoupling mechanisms were intended to begin the transition away from traditional COSR and "move Hawaii toward a clean energy future, while also protecting the financial health of the HECO Companies."[7] The triennial rate case cycle provided an opportunity to reduce regulatory burden and costs, while maintaining a sufficient degree of oversight as these new mechanisms were implemented.

While Hawaii has made substantial progress towards transitioning to a new regulatory model, it is evident that further action is required to achieve the goals of a financially healthy utility supporting the State's clean energy future. Concerns with cost control persist,[8] and general rate case applications during

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[5]Docket No. 2008-0274, Final Decision and Order; and Dissenting Opinion of Leslie H. Kondo, Commissioner, filed August 31, 2010 ("Decoupling D&O"), at 123-125.

[6]Decoupling D&O at 4.

[7]Decoupling D&O at 5.

[8]See In re Public Util. Comm'n, Docket No. 2013-0141, Decision and Order No. 31908, filed February 17, 2014, at 29-51 (instituting an annual cap on allowed interim recovery of costs recoverable through the RAM ("RAM Cap")).

the triennial rate case cycle have consistently sought increases above the Companies' current effective rates.[9] As Hawaiian Electric pilots the way toward the State's goals for clean energy transformation, it is imperative that this transformation be borne fairly between shareholders, who benefit from utility earnings, and customers, who currently experience persistently high electricity rates.

Surveying this regulatory landscape, and eyeing the vital and necessary changes still to come to achieve the State's clean energy transformation, the Commission recognized that a fundamental change in the regulatory framework was necessary to sustain the transition toward a regulatory model that holistically

[9]See In re Hawaii Elec. Light Co., Inc., Docket No. 2015-0170, Application filed September 19, 2016 (seeking a rate increase of $19,291,000 over revenues at current effective rates based on a 2016 test year); In re Hawaiian Elec. Co., Inc., Docket No. 2016-0328, Application, filed December 16, 2016 (seeking a rate increase of $106,383,000 over revenues at current effective rates based on a 2017 test year); In re Maui Elec. Co., Ltd., Docket No. 2017-0150, Application, filed October 12, 2017 (MECO seeking a rate increase of $30,062,000 over revenues at current effective rates based on a 2018 test year); In re Hawaii Elec. Light Co., Inc., Docket No. 2018-0368, Application, filed December 14, 2018 (HELCO seeking a rate increase of $13,350,000 over revenues at current effective rates based on a 2019 test year); and In re Hawaiian Elec. Co., Inc., Docket No. 2019-0085, Application, filed August 21, 2019 (HECO seeking a rate increase of $77,554,000 over revenues at current effective rates based on a 2020 test year).

aligns utility interests with customer needs and the State's clean energy goals.

Accordingly, in April 2018, the Commission issued Order No. 35411, initiating this proceeding to evaluate opportunities for updating the regulatory framework for Hawaiian Electric, in light of a transforming electric power system.[10] In particular, the Commission noted the following circumstances: the transition from centralized fossil-fueled generation systems toward distributed and renewable energy systems; the increase in variable generation from Distributed Energy Resources ("DER") and concomitant desire for more customer choice and control over their electrical energy consumption; and the State's policy shift towards reducing fossil-fuel use and related greenhouse gas ("GHG") emissions.[11]

As a result, the Commission observed that as the role and responsibilities of Hawaiian Electric rapidly change, so should the nature of the Commission's regulation, in order to meet these evolving circumstances.[12] In addition, as noted above, the current rate environment, where customers are burdened by

[10]See Order No. 35411, "Instituting a Proceeding to Investigate Performance-Based Regulation," filed April 18, 2018 ("Order No. 35411").

[11]Order No. 35411 at 1-2.

[12]See Order No. 35411 at 2-3.

persistently high electricity costs, is unsustainable and, ultimately, unacceptable in the long run.

The Commission concluded that "PBR enables regulators to reform legacy regulatory structures to enable innovations within modern power systems[,]" by "attempt[ing] to address some of the issues and disincentives inherent in traditional [COSR] through a set of alternative regulatory mechanisms intended to focus utilities on performance and alignment with public policy goals, as opposed to growth in capital investments or other traditional determinants of utility earnings under COSR."[13]

To accomplish this ambitious vision, the Commission established a comprehensive work plan, divided into two phases in this proceeding. Phase 1 was intended to "examine the current regulatory framework and identify those areas of utility performance that are deserving of further focus for PBR [F]ramework development and/or PIMs in Phase 2."[14] Phase 2 was intended to build on Phase 1 and focus on refining and/or modifying the Commission's existing regulatory framework to address the areas identified in Phase 1 as ripe for improvement.[15]

[13]Order No. 35411 at 3.

[14]Order No. 35411 at 53.

[15]See Order No. 35411 at 55.

Phase 1 consisted of a series of technical workshops and briefings, which was summarized in a Staff Proposal released in February 2019.[16] Following a discovery period and briefing by the Parties, during which they provided feedback on the Phase 1 Staff Proposal, Phase 1 culminated with the Commission's Phase 1 D&O, which "establish[ed] the regulatory principles, goals, and outcomes to guide Phase 2, and identifie[d] a portfolio of specific PBR mechanisms for prioritized examination and development[,]"[17] which are summarized below:

PBR Guiding Principles[18]

1. **A customer-centric approach.** A PBR framework should encourage the expanding opportunities for customer choice and participation in all appropriate aspects of utility system functions, including verifiable "day-one" savings for customers.

2. **Administrative efficiency.** PBR offers an opportunity to simplify the regulatory framework and enhance overall administrative efficiency.

3. **Utility financial integrity.** The financial integrity of the utility is essential to its basic obligation to provide safe and reliable

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[16]See Order No. 35542 at 57; see also, Letter From: Commission To: Service List Re: Staff Proposal for Updated Performance-Based Regulations – Docket No. 2018-0088, In re Public Utilities Commission, Instituting a Proceeding to Investigate Performance-Based Regulation, filed February 7, 2019 ("Phase 1 Staff Proposal").

[17]Phase 1 D&O at 1-2.

[18]Phase 1 D&O at 6.

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.

PBR Goals and Outcomes[19]

Table 1: PBR Goals and Outcomes		
Goal	**Regulatory Outcome**[20]	
Enhance Customer Experience	*Traditional*	Affordability
		Reliability
	Emergent	Interconnection Experience
		Customer Engagement
Improve Utility Performance	*Traditional*	Cost Control
	Emergent	DER Asset Effectiveness
		Grid Investment Efficiency

[19]Phase 1 D&O at 7.

[20]As described in the Phase 1 Staff Proposal, regulatory outcomes can be distinguished between "traditional" and "emergent." "Traditional outcomes have been ingrained in utility regulations for many years and, while not immutably achieved or secured in current regulations, they are at least partially addressed." Conversely, "[e]mergent outcomes include those that need attention as Hawaii progresses towards a 100% RPS, as the electricity system becomes more renewable and distributed, and as the HECO Companies pursue opportunities for non-traditional asset investments and services." Phase 1 Staff Proposal at 16.

<table>
<tr><td rowspan="5">Advance Societal Outcomes</td><td rowspan="2">Traditional</td><td>Capital Formation</td></tr>
<tr><td>Customer Equity</td></tr>
<tr><td rowspan="3">Emergent</td><td>GHG Reduction</td></tr>
<tr><td>Electrification of Transportation</td></tr>
<tr><td>Resilience</td></tr>
</table>

In June of 2019, Phase 2 officially began with Order No. 36388, in which the Commission set forth the procedural schedule to govern Phase 2.[21] Phase 2 continued the collaborative nature of Phase 1 by beginning with a Working Group process ("Working Group Process"), during which the Parties participated in working groups, Party-led subgroups, and specialized workshops to investigate, discuss, vet, and consider various proposals for specific PBR mechanisms that would comprise the overall PBR Framework.[22] Following the Working Group Process, a more formal briefing process ("Briefing Process") allowed the Parties to each present their vision of a comprehensive PBR Framework for Hawaiian Electric, including proposals for specific PBR mechanisms. These proposals were then vetted through a discovery

[21]See Order No. 36388, "Convening Phase 2 and Establishing a Procedural Schedule," filed June 26, 2019 ("Order No. 36388").

[22]See Order No. 36388 at 9.

process and subsequent briefing to further refine the Parties' proposals.[23]

On September 21-23, 2020, the Commission held a panel hearing during which the Parties gave brief presentations of their proposals, followed by examination of Party witnesses by the Commission. Thereafter, the Parties submitted post-hearing briefs between October 15-19, 2020.

Following the Parties' post-hearing briefing, the Commission continued to issue Information Requests ("IRs") to the Parties seeking further clarification and/or input on various proposals for specific PBR mechanisms. In so doing, the Commission further investigated the Parties' proposals and solicited input on alternatives.

This has all contributed to developing the record in support of the PBR Framework approved in this D&O, which is summarized in the table below:

[23]See Order No. 36388 at 16.

Table 2: Summary of PBR Framework	
Revenue Adjustment Mechanisms	
Multi-year Rate Period ("MRP") with Indexed Revenue Adjustment	**5-Year Control Period** beginning with current effective rates and subsequently modified according to an annual review cycle by an **externally indexed Revenue Adjustment** allowing revenue changes during the MRP: **Annual Revenue Adjustment** = (**I-Factor**) - (**X-Factor**) + (**Z-Factor**) **–** (**Customer Dividend**) Where: I-Factor (inflation) = Gross Domestic Product Price Index X-Factor (productivity) = a pre-determined annual productivity factor set at 0%. Z-Factor (exogenous events) = ex post adjustment, determined annually, to account for exogenous events outside of the utility's control. Customer Dividend = mechanism to ensure that customers share in the benefits of the PBR Framework, composed of: (1) a 0.22% annual compounding factor; and (2) $22.16 million, representing the Companies' prior commitment to return $25 million in annual savings as a result of the Management Audit recently conducted in HECO's last general rate case, determined on a cash basis and averaged over the MRP. In the fourth year of the MRP, the Commission will comprehensively review the PBR Framework to determine if any modifications or revisions are appropriate. It is expected that the post-MRP will consist of some refined version of the PBR Framework, rather than a return to traditional COSR.
Exceptional Project Recovery Mechanism ("EPRM")	The **EPRM** will continue to provide "above the ARA" relief for extraordinary projects on a case-by-case basis, in an application process that is largely unchanged from the previous Major Project Interim Recovery process it replaces; however, EPRM relief is now explicitly applicable to O&M expenses and program costs, not just capital expenditures, to mitigate capex bias.
Revenue Decoupling and Existing Cost Trackers	**Revenue decoupling** (i.e., the Revenue Balancing Account) will continue to be used to true up collected revenues to an annual revenue target. Likewise, existing **cost tracking mechanisms** (e.g. PPAC, ECRC, etc.) will continue to track and recover certain approved costs.

Performance Mechanisms	
Performance Incentive Mechanisms ("PIMs")	A portfolio of **PIMs** designed to drive achievement of the following priority Outcomes: **RPS-A**: a PIM designed to incent Hawaiian Electric to accelerate the achievement of its Renewable Portfolio Standards goals, promoting the Outcomes of *DER Asset Effectiveness, Customer Engagement, Interconnection Experience, Cost Control, Affordability, Grid Investment Efficiency*, and *GHG Reduction*. **Grid Services PIM**: a PIM designed to promote *DER Asset Effectiveness*, as well as *Grid Investment Efficiency*, by incenting the expeditious acquisition of grid services capabilities from DERs. **Interconnection Approval PIM**: a PIM designed to promote *Interconnection Experience* by incenting faster interconnection times for DER systems <100 kW, while penalizing underperformance. **LMI Energy Efficiency PIM**: a PIM intended promote *Customer Engagement,* as well as *Customer Equity*, and *Affordability*, by incenting collaboration between Hawaiian Electric and Hawaii Energy, the third-party Public Benefits Fee Administrator, to deliver energy savings for low- and moderate-income ("LMI") customers. **AMI Utilization PIM**: a PIM intended to promote *Customer Engagement* and *DER Asset Effectiveness*, as well as *Grid Investment Efficiency*, by incenting acceleration of the number of customers with advanced meters enabled to support time-varying rates and next generation DER programs. **Existing SAIDI/SAIFI and Call Center PIMs**: These PIMs will continue and may be updated in the Post-D&O Working Group. The SAIDI and SAIFI PIMs will continue to support *Reliability*, and the Call Center PIM will continue to support *Customer Engagement*.
Shared Savings Mechanisms ("SSMs")	Incorporation of project/program-specific performance mechanisms, including **shared savings mechanisms** to incent cost-effective procurement of renewable energy generation and grid services. Alternative incentive structures may also be considered.

Performance Mechanism Working Group	In recognition of the evolving nature of PBR, the PBR Framework provides for an on-going working group during the MRP to offer a forum to continue examining and developing Performance Mechanisms, which may be implemented during the MRP. The Post-D&O Working Group will begin with finalizing details regarding the Interconnection Approval PIM, LMI Energy Efficiency PIM, and the AMI Utilization PIM, as well as determining an initial portfolio of **Scorecards** and **Reported Metrics** to be published by Hawaiian Electric to track, measure, and evaluate performance against targeted performance levels for other priority Outcomes. Thereafter, other Performance Mechanisms may be considered for further development.
Non-Revenue Initiatives	
Pilot Process	A framework for conducting expedited review for pilot projects to incent development of innovative programs and projects. Annual reports will allow the Commission to monitor progress and ensures appropriate cost recovery. Successful pilots may be considered for expansion.
Safeguards	
Earnings Sharing Mechanism ("ESM")	A risk-mitigation mechanism which protects the utility and customers from excessive earnings or losses, as measured by Hawaiian Electric's Return on Equity ("ROE") as follows: Target ROE of 9.5%, surrounded by a neutral deadband of 300 basis points ("bps") in both directions (no sharing if actual ROE is between 6.5% and 12.5%). 50-50 sharing between customers and the utility of earnings for actual earnings falling within 150 bps outside the deadband in either direction (50-50 sharing if actual ROE is <6.50% to 5.00% or >12.50% to 14.0%). 90-10 sharing between customers and the utility for any further earnings and losses (90-10 sharing if actual ROE is <5.00% or >14.00%). Adjustments resulting from **downward** ESM adjustments (decreases to actual ROE) will come in the following year as a mid-year addition to ARA revenues. Adjustments resulting from **upward** ESM adjustments (increases to actual ROE) will be shared with customers as a bill credit commencing in the following year.

Re-Opener	In addition to protections provided by the **ESM**, the PBR Framework will also incorporate a **Re-Opener** mechanism, under which the Commission will open an examination into all or parts of the PBR framework, at its discretion, to determine if adjustments or modifications to specific PBR mechanisms are appropriate. A **Re-Opener** investigation will be triggered if Hawaiian Electric's credit rating outlook indicates a potential credit downgrade below investment-grade status (as determined by one of the three major credit rating agencies), or if its earned ROE enters the outermost sharing tiers of the ESM (actual ROE is <5.0% or >14.0%).

The PBR Framework described above is intended to take advantage of opportunities to improve the current regulatory framework and creates a win-win situation for both the Companies and their customers. The innovative regulatory mechanisms described above, coupled with the many Revenue Adjustment Mechanisms and Safeguards, will provide the Companies with strong, but balanced, incentives to contain costs and deliver exceptional performance on high priority outcomes. Achieving the various targets in the PIM Portfolio will significantly boost the Companies' financial position, while also providing customers with improved service and offerings.

The PBR Framework also builds on the existing performance mechanisms previously established in Docket

Nos. 2013-0141[24] and 2017-0352[25] and continues to implement the spirit of HRS § 269-16.1 by implementing additional "performance incentives and penalty mechanisms that directly tie an electric [utility's] revenues to that utility's achievement on performance metrics and break the direct link between allowed revenues and investment levels."[26] In particular, the PBR Framework provides new incentives and penalties, as reflected in Table 2, above, to promote, among other things: "customer engagement and satisfaction,"[27] "[a]ccess to utility system information,"[28] "[r]apid integration of renewable energy sources, including quality interconnection of customer-sited resources,"[29] and "[t]imely execution of competitive procurement, third-party interconnection, and other business processes."[30]

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[24]See Docket No. 2013-0141, Order No. 34514, "Establishing Performance Incentive Measures and Addressing Outstanding Schedule B Issues," filed April 27, 2017 ("Order No. 34514"), at 27-63.

[25]See In re Hawaiian Elec. Co., Inc., et al., Docket No. 2017-0352, Order No. 36604, "Establishing Performance Incentive Mechanisms for the Hawaiian Electric Companies' Phase 2 Requests for Proposals," filed October 9, 2019 ("Order No. 36604"), at 18-31.

[26]HRS § 269-16.1.

[27]HRS § 269-16.1(b)(4).

[28]HRS § 269-16.1(b)(5).

[29]HRS § 269-16.1(b)(6).

[30]HRS § 269-16.1(b)(7).

The need for such transformation is particularly urgent in light of the economic impacts resulting from the global COVID-19 pandemic. As Hawaiian Electric customers, already experiencing high electricity rates, are faced with the grim economic realities brought on by the pandemic, the implementation of the PBR Framework is particularly timely. The PBR Framework's cost control incentives will facilitate downward pressure on electricity rates, while the annual Customer Dividend ensures that customers immediately, and continually, share in the expected benefits of the PBR Framework.

Further, as the Companies respond to the performance incentives provided under the PBR Framework, there should be an acceleration in the integration of renewable generation, which will decrease the State's reliance on imported, and costly, fossil fuels. As the PBR Framework also rewards the push to develop renewable projects, the improved use and scope of DERs, and increased access to energy efficiency programs for low- and moderate-income ("LMI") customers, it will support the local renewable energy workforce during this time of economic challenges. Moreover, the expedited Pilot Process will support the development of innovative projects and foster partnerships between Hawaiian Electric and local businesses.

At the same time, the PBR Framework offers numerous opportunities for the Companies to significantly improve their financial condition by implementing cost containing measures and earning rewards for meeting performance goals. Safeguards have been built into the PBR Framework to protect the Companies from substantial, persistent financial harm and provide them with the support necessary to move forward with this necessary transformation despite the economic challenges brought on by the COVID-19 pandemic.

Thus, in addition to continuing the transformation of Hawaii's electric utilities, the PBR Framework can complement the state-wide efforts already underway to address the economic impacts of the COVID-19 pandemic and provide opportunities to continually improve the relationship between utility and customer.

II.

PROCEDURAL HISTORY[31]

On May 23, 2019, the Commission issued the Phase 1 D&O, which established the regulatory principles, goals, and outcomes to guide Phase 2 of this proceeding and identified a portfolio of

[31]The procedural history for Phase 1 can be found in Appendix A to the Phase 1 D&O.

PBR mechanisms for prioritized examination and development during Phase 2.

On June 26, 2019, the Commission issued Order No. 36388, which formally convened Phase 2 and established a procedural schedule. Order No. 36388 announced that Phase 2 would be split into two sequential sub-phases: (1) the Working Group Process, where a Revenue Adjustment Mechanism Working Group ("RWG") and a Performance Mechanism Working Group ("PWG") would be used to investigate critical issues, evaluate options, and develop proposals for the specific regulatory mechanisms identified in the Phase 1 D&O; and (2) the formal Briefing Process, which would incorporate more traditional procedural steps, such as opportunities for discovery, briefing, and a panel hearing.[32] Participation in the working groups was optional, but, as a practical matter, most Parties elected to participate in both the RWG and PWG.

This structure was intended to create a collaborative environment during the Working Group Process, where Parties could discuss and vet ideas informally, in preparation for developing comprehensive PBR proposals. This was followed by the Briefing Process, where the Parties' comprehensive PBR proposals

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[32]See Order No. 36388 at 8-9 and 14-15.

would then be subject to traditional review via IRs, position statements, and a panel hearing.[33]

The Working Group Process consisted of four technical workshops, interspersed with monthly working group meetings for both the RWG and PWG, and ran from August 7, 2019, the date of the first technical workshop, through May 21-22, 2020, the date of the fourth technical workshop. As the Working Group Process was intended to be informal and foster collaboration among the Parties, the meetings and workshops were not recorded. However, initial PBR proposals developed by the Parties during this process were filed in the record on August 14, 2019, and subsequently updated on January 15, 2020, and May 13, 2020.

On May 18, 2020, the Commission issued Order No. 37142, which modified the procedural schedule pertaining to the Briefing Process.[34] In particular, the Commission provided specific deadlines to replace the placeholders originally provided in Order No. 36388 and incorporated additional procedural steps to clarify motions and briefing regarding the panel hearing.[35] Additionally, the Commission moved up the date of the panel hearing

[33] See Order No. 36388 at 8.

[34] Order No. 37142, "Modifying the Procedural Schedule," filed May 18, 2020 ("Order No. 37142").

[35] See Order No. 37142 at 4-5.

from October 2020 to September 2020, to accommodate the Commission's intention of issuing this D&O by December 2020.[36]

On June 2, 2020, the Commission issued Order No. 37162, which granted Hawaiian Electric's request for a brief extension of time by which to submit its Initial Statement of Position ("ISOP").[37] As a result, the Commission extended the deadline by which the Parties' ISOPs were due from June 10, 2020, to June 18, 2020.

Thereafter, on June 18, 2020, the Parties submitted their ISOPs, which reflected their comprehensive proposals for a PBR Framework.[38]

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[36]Order No. 37142 at 5-6.

[37]Order No. 37162, "Granting the Letter Request Filed by the Hawaiian Electric Companies," filed June 2,2020 ("Order No. 37162").

[38]"Ulupono Initiative, LLC's Initial Statement of Position; and Certificate of Service," filed June 18, 2020 ("Ulupono ISOP"); "City and County of Honolulu's Phase 2 Initial Comprehensive Proposal Third Update; Declaration of Roy K. Amemiya, Jr.; and Certificate of Service," filed June 18, 2020 ("C&CH ISOP"); "County of Hawaii's Initial Statement of Position; and Certificate of Service," filed June 18, 2020 ("COH ISOP"); "Phase 2 Statement of Position of the Hawaiian Electric Companies; Exhibits "A" Through "Q"; and Certificate of Service," filed June 18, 2020 ("Hawaiian Electric ISOP"); "Blue Planet Foundation's Phase 2 Initial Statement of Position; Exhibits A & B; and Certificate of Service," filed June 18, 2020 ("Blue Planet ISOP"); and "Division of Consumer Advocacy's Phase 2 Initial Statement of Position; and Certificate of Service," filed June 18, 2020 ("Consumer Advocate ISOP").

In July and August 2020, the Parties issued and responded to IRs from each other.[39] The Commission also issued IRs to the Parties during this period.

In their ISOP, the C&CH clarified that "due to the COVID-19 pandemic, the City's continued efforts to stand up relief, response, and recovery capacity, staff and resources assigned to the City intervention in this proceeding have been re-assigned to critical emergency response and economic recovery functions." As such, the C&CH stated that it was standing on its analysis and recommendations in its initial August 14, 2019, proposal and subsequent updates. Id. Accordingly, this D&O references the C&CH's proposal updates, rather than its ISOP, for precision.

In lieu of an ISOP, LOL filed a Joinder to Ulupono's earlier May 13, 2020 proposal update. "Life of the Land's Statement of Position; Joinder to Ulupono Initiative LLC's Second Proposal Update; and Certificate of Service," filed June 18, 2020 ("LOL ISOP"). LOL further stated that "[w]e probably support Ulupono Initiative's Statement of Position being filed simultaneously with this filing, based on working group meetings, but we have not seen the document." Id. at 1 n.2. See also, "Life of the Land's Reply Statement of Position; and Certificate of Service," filed August 20, 2020 ("LOL RSOP"), at a 4-5 ("Life of the Land has carefully evaluated the statements of positions of different parties and responses to information requests, and found that we strongly agree with all of the approaches, methods, and solutions proposed by Ulupono – excluding their Greenhouse Gas ('GHG') Performance Incentive Mechanism . . . .").

Similarly, HSEA, DERC, and HPVC filed a joinder to Blue Planet's ISOP, in lieu of an ISOP. "Hawaii Solar Energy Association[,] Di[s]tributed Energy Resource's [sic] Council of Hawaii[,] and Hawaii PV Coalition's Joinder to Blue Planet Foundation's Statement of Position; and Certificate of Service," filed June 18, 2020 ("DER Parties ISOP").

[39]See Order No. 37142 at 4-5.

On August 20, 2020, the Parties submitted their Reply Statements of Position ("RSOP").[40]

On September 2, 2020, in preparation for the panel hearing, the Commission issued a letter to the Parties. Noting the significant change in circumstances arising from the global COVID-19 pandemic, as well as the State's local response, the Commission observed that adjustments must be made to the panel hearing to comply with State policies and in the interests of the participants' health and safety.[41] In lieu of holding the panel hearing in person at the Commission's main office, as originally planned, the Commission announced that it would be holding the

[40]"County of Hawaii's Reply Statement of Position; and Certificate of Service," filed August 20, 2020 ("COH RSOP"); LOL RSOP; "Ulupono Initiative LLC's Phase 2 Reply Statement of Position; and Certificate of Service," filed August 20, 2020 ("Ulupono RSOP"); "City and County of Honolulu's Reply Statement of Position; Declaration of Roy K. Amemiya, Jr; and Certificate of Service," filed August 20, 2020 ("C&CH RSOP"); "Blue Planet Foundation's Phase 2 Reply Statement of Position; and Certificate of Service," filed August 20, 2020 ("Blue Planet RSOP"); "Phase 2 Reply Statement of Position of the Hawaiian Electric Companies; Exhibits "A" Through "H"; and Certificate of Service," filed August 20, 2020 ("Hawaiian Electric RSOP"); and "Division of Consumer Advocacy's Phase 2 Reply Statement of Position," filed August 20, 2020 ("Consumer Advocate RSOP"). The DER Parties did not file a RSOP.

[41]Letter From: Commission To: Service List Re: Remaining Procedural Steps – Docket No. 2018-0088, In re Public Utilities Commission, Instituting a Proceeding to Investigate Performance-Based Regulation, filed September 2, 2020 ("Hearing Letter").

panel hearing virtually, with the Parties and their witnesses participating via Webex.[42] The Commission presented the Parties with three alternative formats and solicited their preference:

> Option A reflects a more formal evidentiary hearings with panels of witnesses for identified topics available for cross-examination by the Commission, Commission staff, and the Parties.
>
> Option B more closely resembles prior Commission panel hearings from past investigative proceedings (see, e.g., the Docket No. 2013-0141 panel hearing on decoupling "Schedule B" issues, held in October 2014), where questioning is done solely by the Commission and Commission staff, and Parties are given the opportunity to make opening remarks, responsive statements, and closing statements.
>
> Option C represents a more informal option and contemplates panel discussions in a technical conference setting, focused on specific issues and questions issued by the Commission ahead of the technical conference.[43]

The Parties were instructed to inform the Commission of their preference in writing by September 8, 2020.[44]

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[42]Hearing Letter at 1.

[43]Hearing Letter at 1-2.

[44]Hearing Letter at 2.

By September 8, 2020, the Parties expressed a preference for an "Option C" type hearing.[45]

On September 10, 2020, the Commission held a Prehearing Conference with the Parties to review the procedures for the panel hearing, which was scheduled to begin

[45]See Letter From: D. Matsuura To: Commission Re: Docket No. 2018-0088 – Instituting a Proceeding to Investigate Performance-Based Regulation; Hawaiian Electric Response to Commission Letter Regarding Evidentiary Hearing, filed September 4, 2020; Letter From: D. Codiga To: Commission Re: Docket No. 2018-0088: In the Matter of Public Utilities Commission Instituting a Proceeding to Investigate Performance-Based Regulation; Response to Commission Letter Regarding Hearing Options, filed September 8, 2020; County of Hawaii's Comments; Docket No. 2018-0088, filed September 8, 2020; City and County of Honolulu's Responses to the Commission's September 2, 2020 Letter Regarding Remaining Procedural Steps; Declaration of Roy K. Amemiya, Jr.; Docket No. 2018-0088, filed September 8, 2020; Letter From: I. Moriwake To: Commission Re: Docket No. 2018-0088: Blue Planet's Response to the Commission's September 2, 2020 Letter Soliciting Parties' Preferences for the Hearing, filed September 8, 2020 (Blue Planet indicated that its preference was for Option B or C over Option A, but did not exhibit a strong preference between Option B or Option C); and Letter From: Consumer Advocate To: Commission Re: Docket No. 2018-0088 – Instituting a Proceeding to Investigate Performance-Based Regulation: Response to the Hawaii Public Utilities Commission September 2, 2020 Letter, filed September 8, 2020 (the Consumer Advocate couched its preferred option in terms of the Commission's assumptions going into the hearing. Ultimately the Consumer Advocate supported a format under which the Commission would question a panel of Party witnesses, with an opportunity for Parties to submit proposed questions to the Commission ahead of the hearing for the Commission's consideration. See id. at 2).

September 21, 2020.[46] In addition to confirming that the hearing would be held virtually through Webex, the Commission also informed the Parties that it would be livestreaming the panel hearing via YouTube and that a recording of the hearing would be made available to the Parties following the hearing.[47] On September 11, 2020, the Commission issued the Prehearing Conference Order, which affirmed the discussion at the Prehearing Conference.

The panel hearing began on September 21, 2020, and concluded on September 23, 2020. On September 29, 2020, the Commission issued a letter to the Parties, confirming that a recording of the hearing could be accessed through the YouTube channel the Commission had previously established, links to which had been sent to the Parties on September 24, 2020.[48]

Between October 15-19, 2020, the Parties submitted their post-hearing briefs.[49]

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[46]See Order No. 37314, "Prehearing Conference Order," filed September 11, 2020 ("Prehearing Conference Order").

[47]Prehearing Conference Order at 5. See also, Letter From: Commission To: Parties Re: Docket No. 2018-0088 – In re Public Utilities Commission, Instituting a Proceeding to Investigate Performance-Based Regulation, filed September 24, 2020.

[48]Letter From: Commission To: Parties Re: Docket No. 2018-0088 – In re Public Utilities Commission, Instituting a Proceeding to Investigate Performance-Based Regulation, filed September 29, 2020.

[49]"City and County of Honolulu's Post-Hearing Briefing; and Certificate of Service," filed October 15, 2020; "Life of the

Throughout the pre-hearing period, and continuing through the post-hearing period, the Commission continued to issue IRs to the Parties.

Pursuant to the procedural schedule for Phase 2, as set forth in Order No. 36388, as modified by Order No. 37142, no further procedural steps are contemplated, and Phase 2 is ready for decision making.

III.

PARTIES AND POSITIONS

The Parties' positions are exhaustively documented in the voluminous filings submitted in both Phase 1 and Phase 2 of this docket. As it pertains to Phase 2, during the Working Group Process, the Parties submitted a conceptual proposal in

Land's Post-Hearing Brief; and Certificate of Service," filed October 19, 2020; "County of Hawaii's Post-Hearing Brief; and Certificate of Service," filed October 19, 2020; "Hawaii PV Coalition, Hawaii Solar Energy Association and Distributed Energy Resource Council of Hawaii Post Hearing Brief; and Certificate of Service," filed October 19, 2020; "Ulupono Initiative LLC's Post-Hearing Brief; and Certificate of Service," filed October 19, 2020; "Post-Hearing Brief of the Hawaiian Electric Companies; Exhibit 1; and Certificate of Service," filed October 19, 2020; "Division of Consumer Advocacy's Post-Hearing Brief; Exhibit A; and Certificate of Service," filed October 19, 2020; and "Blue Planet Foundation's Post-Hearing Brief; and Certificate of Service," filed October 19, 2020.

August 2019, which was then supplemented by updates, based on progress in the Working Groups, in January 2020 and May 2020.

The Briefing Process began with the submission of formal, comprehensive proposals in the form of the Parties' ISOPs on June 18, 2020, which, after vetting through IRs, were supplemented by their RSOPs on August 20, 2020. Following the panel hearing held from September 21-23, 2020, the Parties further iterated their positions through post-hearing briefs filed between October 15-19, 2020.

For purposes of this D&O, only the pertinent parts of the record are referenced. However, electronic access to the entire record in this proceeding can be found through the Commission's Document Management System, available at https://dms.puc.hawaii.gov/dms/index.jsp, and by entering "2018-0088" in "Docket Quick Link" function.

IV.

DISCUSSION

As discussed below, the PBR Framework approved today establishes 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 revenues during the MRP.

Hawaiian Electric may supplement the annual ARA-determined revenues ("ARA Revenues") by seeking relief for extraordinary projects or programs though the Exceptional Project Recovery Mechanism ("EPRM"), which is replacing the Major Projects Interim Recovery ("MPIR") mechanism, or by earning significant financial rewards for exemplary performance as provided through a portfolio of Performance Incentive Mechanisms ("PIMs") and Shared Savings Mechanisms ("SSMs").

Decoupling will continue, whereby the Companies' annual revenues allowed under the PBR Framework will be incorporated into their target revenues, which will be accrued and collected through the operation of the RBA. Similarly, existing cost recovery mechanisms for approved costs not recovered through target revenues will continue to operate as currently provided (e.g., the Energy Cost Recovery Clause ("ECRC"), Purchased Power Adjustment Clause ("PPAC"), Demand Response Adjustment Clause ("DRAC"), Demand Side Management surcharge ("DSM"), pension and Other Post-Employment Benefits ("OPEB") tracking mechanisms, etc.).

The PBR Framework will incorporate a variety of non-revenue provisions as well, including Scorecards, Reported Metrics, and an expedited Pilot Process.

A Post-D&O Working Group ("Post-D&O Working Group") is established to address the final details of several of Performance Mechanisms, including several of the PIMs and the portfolio of Scorecards and Reported Metrics. Thereafter, the Post-D&O Working Group may address additional PIM and/or SSM proposals that were introduced in this proceeding, but not fully developed in time to be included in this D&O. Depending on the progress of the Post-D&O Working Group, the Commission may subsequently approve some of these proposals during the MRP, thereby increasing opportunities for the Companies.

To protect against unintended consequences, the Commission's PBR Framework incorporates a number of safeguards to protect both Hawaiian Electric and its customers from extreme and/or deleterious impacts. First, an Earnings Sharing Mechanism ("ESM") will annually compare Hawaiian Electric's earned Return on

Equity ("ROE") to a baseline of 9.50%[50] and determine an appropriate "sharing" of earnings or costs based on changes in Hawaiian Electric's earned ROE according to pre-determined sharing ratios established in this D&O. This will mitigate extreme fluctuations in earnings or costs, as the sharing adjustments will dull the accrual of excessive or deficient earnings to Hawaiian Electric.

Second, if the Companies' earned ROE in a given year enters the outermost sharing tiers of the ESM, or if the Companies' credit rating outlook indicates a potential credit rating downgrade below investment-grade status (as determined by one of the three major credit rating agencies),[51] the Companies may utilize a Re-Opener mechanism under which the Commission will review any relevant PBR mechanism(s) to determine if any modifications are necessary.

Third, during the MRP, the Commission will review and adjust the Companies' target revenues according to an annual review cycle. This will involve, at a minimum, biannual determination of the ARA factor amounts and any adjustments arising from approved

[50]A 9.50% ROE reflects the ROE for Hawaiian Electric as reflected in each of the Companies' most recent general rate case proceedings. See Docket Nos. 2017-0150 (MECO), 2018-0368 (HELCO), and 2019-0085 (HECO).

[51]Moody's, Standard & Poor's, and Fitch.

EPRM projects, PIMs or SSMs, approved pilot projects, and the "sharing" feature of the ESM, which will provide the Commission with an opportunity to determine if any of these mechanisms are not operating as intended.

Fourth, during the fourth year of the MRP, the Commission will conduct a comprehensive review of the PBR Framework to determine if the Framework should continue or be modified in any way. Details will be provided nearer to the fourth year of the MRP, and for now, focus should be on gaining experience with the PBR Framework. Although anticipating some modifications to the PBR Framework may be appropriate, the Commission does not envision returning to COSR after the initial MRP.

Collectively, the PBR Framework described above will begin Hawaiian Electric's exciting transition into PBR in a measured and fair manner, balancing cost control measures with opportunities to earn additional revenues through exemplary performance, and bounded by safeguards to address unforeseen events.

The Commission addresses each of these mechanisms in greater detail below.

A.

Annual Revenues

As stated in the Phase 1 D&O, the Commission will implement an MRP during which the Companies' annual revenues will be determined according to a pre-set formula for the duration of the MRP (i.e., the ARA). The ARA formula will determine the revenues that Companies are allowed to collect from ratepayers during the MRP, and does not allow for adjustments based on actual costs (excluding fuel and purchased power, which are recovered separately through the ECRC and PPAC, and other tracking mechanisms). The Companies will be allowed to retain any savings they may achieve through cost reductions (subject to the sharing feature of the ESM). This is intended to incent cost control behavior by the Companies, since rather than seek a general rate increase, their opportunities for additional revenues will arise from increasing efficiency, as well as from earning financial rewards for exemplary performance pursuant to various Performance Mechanisms and case-by-case approval for additional relief for exceptional costs through the EPRM.

1.

Multi-year Rate Period

In the Phase 1 D&O, the Commission indicated its preference for a five-year MRP, during which there would be no general rate case applications, and the Companies would manage their operations with annual revenues adjusted in accordance with the ARA, and as might be supplemented by PIM and SSM awards, as well as any special relief as was then provided by the MPIR.[52] Marginal costs or savings during this period would accrue to the Companies (subject to various safeguard mechanisms, such as the ESM).

Since the Phase 1 D&O was issued, no Party has raised an objection to a five-year MRP, and many have incorporated it into their respective proposals.[53] The Commission continues to believe that a five-year MRP is appropriate for this first iteration of the PBR Framework. A five-year MRP will provide a reasonable opportunity to realize the benefits of the PBR Framework,[54]

[52]The "annual revenues" described here are exclusive of those revenues collected pursuant to existing automatic cost adjustment mechanisms, such as fuel costs under the ECRC and purchased power costs under the PPAC.

[53]See Hawaiian Electric RSOP at 36; Consumer Advocate ISOP at 3; Blue Planet RSOP at 18; COH ISOP at 9; and Ulupono ISOP at 9.

[54]Previously, the Commission had implemented a three-year rate case cycle for the Companies, which was recently terminated in

and will better facilitate the evolution from traditional rate case applications.[55] Accordingly, the PBR Framework will feature a five-year MRP.

2.

Initial Revenues

MECO's existing rates are based on a calendar 2018 test year, where the Commission partially approved the parties' settlement agreement, which resulted in an approximately 3.74% increase in MECO's rates.[56]

HELCO's existing rates are based on a calendar 2019 test year, where the Commission partially approved the parties' settlement agreement, which resulted in maintaining rates at their current effective rates (i.e., a "zero" increase in HELCO's rates).[57]

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anticipation of the PBR Framework. See Docket No. 2008-0274, Order No. 37119, "Terminating Hawaiian Electric's Mandatory Triennial Rate Case Cycle," filed April 29, 2020 ("Order No. 37119").

[55]See also, Phase 1 D&O at 27-28.

[56]See Docket No. 2017-0150, Decision and Order No. 36219, filed March 18, 2019 ("D&O 36219"); and "Parties' Joint Proposed Revised Schedules and Refund Plan," filed April 17, 2019, Exhibit 1C at 1.

[57]See Docket No. 2018-0368, Decision and Order No. 37237, filed July 28, 2020 ("D&O 37237").

HECO's existing rates are based on a calendar 2020 test year, where the Commission partially approved the parties' settlement agreement which also resulted in maintaining rates at their current effective rates; i.e., a "zero" increase in HECO's rates.[58]

The existing effective rates for all three Companies are supplemented by subsequent annual RAM Revenue Adjustments and other approved adjustments to target revenues.

As part of HECO's rate case, the Commission ordered an independent management audit ("Management Audit") of HECO, which subsequently grew to encompass the performance of all of the Companies.[59] The Management Audit concluded that while the Companies' governance structure, regarding oversight by its board and parent company, Hawaiian Electric Industries, Inc., was

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[58]See Docket No. 2019-0085, Decision and Order No. 37387, filed October 22, 2020 ("D&O 37387").

[59]See Docket No. 2019-0085, "Management Audit of the Hawaiian Electric Company (HECO); Final Report; Docket No. 2019-0085," filed May 13, 2020 ("Management Audit"), at 8 (noting that "Increasingly, the 3 companies have transitioned to a One Company Model with most services and functions being provided to all 3 Companies through a common management structure . . . . Accordingly, we will use the collective HECO in this report to include HECO and One Company activities unless specifically stated otherwise.").

A complete, electronic copy of the Management Audit can be found online at the Commission's Document Management System, at https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A20E14A90058F00755.

satisfactory, there were significant operational inefficiencies in various departments that contributed to excessive costs.[60] The Management Audit's findings and recommendations were one of the reasons underlying HECO's decision to agree to a "zero rate increase" in its rate case.[61] As part of the parties' settlement in the HECO rate case, the Companies committed to pass on $25 million in annual savings to customers ("Savings Commitment"), the details of which would be addressed in this docket.[62]

The initial revenues that will be adjusted by the ARA at the beginning of the MRP will be the existing allowed revenue for each of the Companies as of the last date before the pertinent dipositive PBR tariffs become effective. This will reflect the current approved effective revenue for MECO based on its 2018 test year rate case, HELCO based on its 2019 test year rate case, and HECO based on its 2020 test year rate case, as adjusted by subsequent annual RAM Revenue Adjustments and other approved

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[60]See, Management Audit at 12 ("Overall, we estimate that the structural and process improvements we have identified could have the potential to deliver annual benefits for customers, through cost reductions and savings, of as much as $35.7 million on a steady state basis, including a reduction in staffing levels.

[61]See Joint Letter From: J. Viola and Consumer Advocate To: Commission Re: Docket No. 2019-0085 – Hawaiian Electric 2020 Test Year Rate Case; Parties' Joint Stipulated Settlement Letter, filed May 27, 2020 ("HECO Rate Case Settlement"), at 1-2.

[62]See HECO Rate Case Settlement, Exhibit 1 at 33. See also, Decision and Order No. 37387 at 46-53.

adjustments to target revenues as stated in the RBA Provision tariffs for each Company, that are in effect when the new revenue-determining PBR tariffs take effect. In addition to being administratively efficient, the Commission notes that this is consistent with the suggestions of those Parties who have taken a position on this issue.[63] These current effective rates will be adjusted according to the following PBR mechanisms.

3.

Annual Revenue Adjustment Formula

As discussed in the Phase 1 D&O, during the MRP, the Companies' annual revenues will be adjusted according to the following index-driven ARA formula:

ARA Adjustment = (I-Factor) – (X-Factor) + (Z-Factor) – (Customer Dividend)[64]

Much discussion has gone into the determination and application of the various factors used in the ARA formula. After reviewing the record, including the extensive briefing addressing these issues, the Commission establishes the following ARA factors.

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[63]See Hawaiian Electric RSOP at 42-44; and Consumer Advocate RSOP at 99.

[64]Phase 1 D&O at 29.

i.

I-Factor

The I-Factor represents inflation and shall be based on projected changes to the Gross Domestic Product Price Index ("GDPPI").

The I-Factor has not been controversial or disputed, and the Parties have generally coalesced around using an indicator of the annual change in the GDPPI as the inflationary index.[65] The Commission finds this reasonable and will incorporate GDPPI as the I-Factor for the PBR Framework. As discussed below, the GDPPI shall be updated according to an annual review cycle.

ii.

X-Factor

Perhaps no PBR element has fostered as much debate as the X-Factor component of the ARA formula. Representing a pre-determined annual productivity factor by which to annually adjust the Companies' approved previous-year revenues, there has been robust discussion as to how this value should be determined.

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[65] See Hawaiian Electric ISOP at 51; Consumer Advocate ISOP at 3; C&CH January 2020 Proposal Update at 7 and C&CH ISOP at 1 (stating that the C&CH stands by its recommendations in its previous proposal updates); C&CH ISOP at 11-12; and Ulupono ISOP at 18.

As evidenced during the Phase 2 proceedings, different options can be used to evaluate combinations of I-Factor and X-Factor inputs for use in formula-based ratemaking under the ARA. There is the option of using historical or projected financial data, which can involve using either the utility's own financial information, or selected proxy utility financial information from other utilities deemed to be comparable, to determine an appropriate productivity factor. With either option, there are important limitations that need to be considered.

Both the Companies and Blue Planet propose using a "proxy" group of utilities to determine the X-Factor, based on respective methodologies developed by each. The Companies rely on an analysis conducted by the Pacific Economics Group Research, LLC ("PEG Report"), which relied on data gathered for a 15-year period from 45 vertically integrated electric utilities ("VIEUs") on the mainland, analyzing differences in input price growth between the overall economy and utility, to arrive at the Companies' proposed X-Factor of -1.32%.[66]

Blue Planet relies on an analysis performed by Mr. Ronald Binz ("Binz Study"), which relied on data from a proxy group of 67 VIEUs, including those VIEUs selected by the Companies,

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[66]See Hawaiian Electric RSOP at 63. See also, Hawaiian Electric ISOP Exhibits D1 and D2.

but focused on those VIEUs' year-to-year changes in non-fuel revenues over a 25-year period.[67] Blue Planet then further adjusted its data to approximate the effect of an MPIR-like mechanism, which it attributed to years where capital expenditures exceeded the trended average by 33%.[68] Using this methodology, Blue Planet calculated an X-Factor that ranged from -0.06% to -0.56%.[69]

Other Parties, including the Consumer Advocate, the COH, LOL, and Ulupono, support using an X-Factor of "0%," based on the historic experience of the Companies under the Commission's existing decoupling framework, pertinently the annual cap on the amount of annual RAM Revenue Adjustments that can be made to target revenues (i.e., the Ram Cap)[70] as well as the inherent difficulties and limitations in using proxy group studies.[71]

Upon careful review of the record and consideration of the positions of the Parties, the Commission agrees with the

[67]See Blue Planet ISOP at 7-8.

[68]See Blue Planet ISOP at 12.

[69]See Blue Planet ISOP at 14.

[70]The RAM Cap limits the amount of annual RAM Revenue Adjustment to the rate of inflation (i.e., escalation of target revenues by the projected change in GDPPI). In conjunction with an I-Factor equal to the change in GDPPI, the implementation of the existing RAM Cap reflects an equivalent value of "0%" X-Factor.

[71]See Consumer Advocate ISOP at 27-38; Ulupono ISOP at 19-27; COH ISOP at 12; and LOL "Joinder" to Ulupono's ISOP (in which LOL "fully supports the Ulupono position in its entirety.").

Consumer Advocate, Ulupono, the COH, and LOL and adopts an X-Factor of zero (0%) for the ARA formula that will be applied during the MRP. In doing so, the Commission takes into account a number of considerations, including the following:

<u>Reliance on a mainland proxy group is problematic.</u> The Commission is not persuaded that determining the Companies' X-Factor through mainland proxy groups is appropriate.

First it is unclear whether mainland proxy utilities are reasonably comparable to the Companies. Many utilize different generation mixes, require different levels of transmission investment, and commit different amounts to smart grid investments; further, some mainland utilities provide a combination of electrical and gas services.[72] In particular, the Consumer Advocate contends that the VIEU proxy group used for the Companies' PEG Report is embedded with non-recurring trends, such as rapid construction of coal-based plants and mainland-specific transmission investments that distort the proxy

[72]<u>See</u> Ulupono ISOP at 25 ("it will be difficult to develop a truly comparable peer group for establishing the X-Factor based on input prices[,]" noting that Hawaii experiences uniquely higher transportation costs and other price factors, which affect utility operating behavior) and 26 (noting the "high degree of heterogeneity of assets and operating conditions makes it very challenging to develop robust benchmarks for electric utilities."); and Consumer Advocate RSOP at 28-31.

group's comparability to Hawaii and make it a poor basis upon which to base future expectations for Hawaii-specific utilities.

Similarly, decisions regarding which utilities are selected for the proxy group (e.g., size, geographical and climatic location, customer service needs)[73] how they are weighted, from which years data is collected, and which costs are included and excluded impact the results of the analysis and incorporate a large amount of subjective judgment.[74]

Second, the use of various surcharges and other special cost recovery mechanisms by utilities to facilitate particular goals distorts the utility's true reflection of "productivity," adding a further layer of complexity to any attempt of comparison.[75] In this regard, the Companies are further distinguished from their

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[73]See Consumer Advocate ISOP at 29 ("Reliance upon historical cost trends of selected proxy utilities is also problematic, given the uncertainties around how different regulatory regimes, geographic conditions or operating environments within other jurisdictions may have influenced mainland utility management behavior.").

[74]See Consumer Advocate ISOP at 29-30 ("A host of other highly subjective judgments are also needed to select the utilities, identify includable costs or revenues, choose analysis periods that are most relevant and then filter the data to produce meaningful results.").

[75]See Consumer Advocate ISOP at 29 ("There is no reliable method available to isolate and quantify the regulatory mechanisms used by many other regulatory commissions for a multitude of proxy-group utilities to accurately exclude from observed historical cost and revenue trends what portions are properly considered eligible for X-factor inclusion.").

mainland peers due to the operation of the decoupling framework, which requires the Companies to operate under an annual index-driven revenue cap, which may make the Companies' cost recovery structure challenging for direct comparison.[76]

Third, as noted by several of the Parties, none of the VIEUs used in the Companies' PEG Report are subject to a PBR framework "or are otherwise meaningfully similar to the potential PBR mechanisms under consideration in this proceeding."[77] Consequently, "their value in providing an evidentiary basis for adopting a negative X-Factor value is extremely limited."[78]

There are concerns with the methodologies employed by the Companies. In addition to the issues with using mainland VIEUs as a proxy given Hawaii's unique circumstances, the Commission has concerns with other aspects of the Companies' PEG Report's

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[76]See Consumer Advocate ISOP at 30 ("More fundamentally, proxy utilities that have not operated within an index-driving revenue cap regulatory framework are likely to have less rigorously controlled their incurred costs in the past, than should be expected of the Hawaiian Electric Companies under the current process or the soon to be implemented MRP.").

[77]Ulupono ISOP at 20. See also, COH ISOP at 12 (objecting to the comparative value of mainland VIEUs not subject to "PBR-type regulation.").

[78]Ulupono ISOP at 20 (footnote omitted). See also, id. at 23 ("The proposal to base Hawaii's X-Factor on non-Hawaii jurisdictions that are not engaged in such change, and are not evolving toward more transformational PBR mechanisms, strongly undercuts any support the PEG [Report] (even as amended) may provide to adoption of a negative X-Factor.").

methodologies. First, the PEG Report does not distinguish between revenues from major projects that may be recovered through the MPIR (i.e., "above the ARA"), thereby potentially doubly counting these expenditures in its calculations.[79] That is, "[t]o the extent the Companies are available to recover costs through the MPIR adjustment, it is not necessary for the X-Factor to provide for base revenue adjustments."[80]

Second, the PEG Report does not account for growth in Accumulated Deferred Income Taxes ("ADIT") for the VIEUs in its proxy group.[81] As stated by the Consumer Advocate:

> A review of these calculations reveals that PEG, in calculating the return on rate base elements of costs for the VIEUs, has included Plant in Service less Accumulated Depreciation balances, but has completely ignored growth in [ADIT] for all of the VIEU Companies. The omission of ADIT balances has the effect of systematically overstating the growth of invested capital in each VIEU in the PEG sample because ADIT growth provides tax deferral cash flow benefits

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[79]See Ulupono ISOP at 20 (noting that unlike the Companies, which "may recover major project costs through the MPIR adjustment[,] . . . . these VIEUs do not have a dedicated adjustment mechanism for major project costs."); and Consumer Advocate RSOP at 39 ("PEG's inclusion of all VIEU costs without adjustment to exclude the types of costs considered eligible for separate MPIR in Hawaii is a fatal flaw causing the resulting negative X values to be significantly overstated.") (emphasis in the original).

[80]Ulupono ISOP at 22 (footnote omitted).

[81]See Consumer Advocate RSOP at 33-34.

> that directly reduce the amount of investor-supplied capital that is needed to acquire and install new utility plant.[82]

As noted by the Consumer Advocate, "[t]his is a serious omission because the electric utility industry has historically been able to 'finance' much of its new investment in utility plant in recent years with income tax deferrals arising from accelerated tax depreciation and by expensing for tax purposes a 'repairs' deduction on such investments."[83] The Consumer Advocate further observes that, using Hawaiian Electric's recent general rate case filings in Docket No. 2019-0085, "ADIT, Excess ADIT, and unamortized [Investment Tax Credit] balances had grown to about $590 million, or 20.8 percent of average Net Plant in Service at that time of $2,828,549."[84] As the Consumer Advocate contends, this calls into question estimated growth in capital expenditures projections,[85] which helps determine the X-Factor productivity rate.

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[82]Consumer Advocate RSOP at 34.

[83]Consumer Advocate RSOP at 34.

[84]Consumer Advocate RSOP at 35 (citing Docket No. 2019-0085, Application, Direct Testimonies and Exhibits, Book 10, filed August 21, 2019, Hawaiian Electric-2801, at 3).

[85]See Consumer Advocate RSOP at 35-46.

While Blue Planet's Binz Study does not appear to involve some of these concerns,[86] the Commission notes that it still relies on a mainland VIEU proxy group with varying operational considerations.

The Commission has broader concerns with employing a "negative" X-Factor in the ARA. As discussed above, the X-Factor component of the ARA formula is intended to reflect a presumed productivity value achieved by the Companies during the MRP. Thus, a "negative" X-Factor reflects declining performance such that an increase in annual target revenues is required to make up for this decline in productivity.[87] Conceptually, this is at odds with a

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[86]See Consumer Advocate RSOP at 36-37 (noting that the exclusion of ADIT from the PEG Report does not extend to the Binz Study) and 40-43 (acknowledging that the Binz Study's analysis has attempted to quantify and account for the effect of the MPIR).

[87]C.f., Consumer Advocate ISOP at 35 ("As pointed out above, adoption of any negative productivity value would unfavorably impact the affordability regulatory outcome targeted in this proceeding, by locking in higher future target revenues than would occur under the existing capped RAM form of regulation.")

As the ARA formula is established as:

ARA = (I-Factor) – (X-Factor) + (Z-Factor) – (Customer Dividend),

the use of a "negative" value for the X-Factor would translate into a "positive" value, thereby increasing the overall ARA value in the formula.

fundamental premise of PBR, which is to incent exemplary performance and drive improvement in utility operations.[88]

In addition, as stated by Ulupono:

> [Setting a negative X-Factor] may create a perception of false precisions, or result in devoting an excessive level of resources to the task of determining the X-Factor, or may even create opportunities for unproductive gaming of the X-Factor setting analysis. Setting the X-Factor to a very low absolute value (like zero), as a starting position, has merit as well as the advantage of simplicity.[89]

Moreover, the impacts of a negative X-Factor are not insignificant. "Each year the future ARA increase is computed, any negative percentage value for Commission-approved X[-Factor] would directly expand target revenues for each of the three utilities in all subsequent years."[90] According to the Consumer Advocate's calculations, the Companies' proposed -1.32% X-Factor "would impact utility revenues by approximately $72.5 million and earnings by about $49.1 million during the five-year [MRP] . . . . [which] would be additive to all additional revenue increases separately approved . . .

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[88]<u>C.f.</u> Ulupono ISOP at 26 ("More importantly, total factor productivity would be expected to be higher and improve at a faster pace for electric utilities operating in a PBR regime than under traditional [COSR].").

[89]Ulupono ISOP at 27.

[90]Consumer Advocate RSOP at 17.

through [MPIR] mechanism and any Z-factor, REIP, ECRC, PPAC, IRP/DSM and other cost-tracking tariffs."[91] Presented in an alternative context, Ulupono estimates that the Companies' proposal, including a -1.32% X-Factor and estimates of 2% inflation and 0.98% contribution from MPIR, will result in sustained annual growth of 4.3% during the MRP.[92] As stated by Ulupono, "[o]ngoing annual increases of 4.3%, especially regardless of performance, is not sustainable. . . . . [and] would translate into target revenues going up by approximately double the rate of inflation each year."[93]

Relying on historical performance offers a more focused perspective that takes into account the Companies' unique regulatory circumstances. The Companies have currently been operating under a functioning MRP that has served as a reasonable step away from traditional regulatory practices.[94] Through the

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[91]Consumer Advocate RSOP at 17.

[92]See Ulupono RSOP at 40. Ulupono clarified that "[it] requested the Companies to provide 'the amount (in dollars and as a percentage) of the increase in CAGR in target revenues during the period of 2016 to 2019, inclusive, that is attributable to costs recovered . . . through the [MPIR][,]" to which the Companies responded that "0.98% is attributable to the MPIR revenues in terms of target revenues."). Id. (citing Hawaiian Electric response to Ulupono/Hawaiian Electric-IR-2, filed July 23, 2020).

[93]Ulupono RSOP at 40.

[94]See Order No. 37119 (discussing the Companies' existing regulatory framework).

operation of the existing MRP with capped RAM attrition adjustments, the Commission has established a reasonable balancing of customer and utility interests.

As maintained by the Consumer Advocate, as well as other Parties, the current decoupling framework incorporating a GDPPI plus "0%" productivity factor has produced reasonable financial opportunities for the Companies and should be carried over to the ARA formula in the PBR Framework.[95] As a component of the existing decoupling framework, and as will be implemented as part of the ARA in the PBR Framework, the productivity factor affects the Companies' authorized target revenues and, consequently, the Companies' earnings and ROE.

Although the Companies have not consistently achieved their authorized ROE on an annual basis, and thus contend that the

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[95]See Consumer Advocate ISOP at 33 (summarizing the Companies' historical performance under the current regulatory structure featuring GDPPI and a zero productivity offset).

See also, id. at 35 (modeling shows that a zero productivity factor, combined with GDPPI and a symmetrical ESM, appears to be reasonable), 84 (modeling shows that earnings should remain stable and generally within ESM deadband with zero productivity factor if Companies are able to control O&M expense growth at or below general inflation), and Exhibit 4 (modeling results); and Ulupono RSOP at 17 n. 30 ("Insofar as modeling conducted by Ulupono (using the RIST) and the Consumer Advocate (using the Short-Term Model) both reach the same basic conclusions in support of an X-Factor of zero, the Short-Term Model may be considered as extending the results of the RIST modeling, which focuses only on HECO, to HELCO and MECO as well).

existing decoupling framework, with its 0% productivity factor and capped annual adjustment to target revenues, is insufficient,[96] the Commission observes that the rate structure approved for the Companies is not intended to guarantee or serve as an entitlement to a certain ROE, but merely serves as a reasonable opportunity to achieve that ROE.

Further, to the extent the Companies have not historically achieved their authorized ROE under a similar capped, "0% productivity" framework in the past, it is worth noting that the recent Management Audit found substantial inefficiencies and cost savings opportunities for the Companies, indicating that disappointing earnings and ROE may not be solely or fairly attributed to the 0% productivity factor or capped nature of the decoupling framework. If timely addressed, these identified opportunities, complemented by the incentives and rewards provided under the PBR Framework, may serve to boost the Companies' achieved ROE closer towards their authorized levels.

Going forward, the Companies will have additional opportunities to improve their ROE levels under the new PBR Framework, including:[97]

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[96] See Hawaiian Electric ISOP at 95-99.

[97] See Consumer Advocate ISOP at 33-34.

- Cost control measures that are rewarded under the MRP; i.e., the Companies can significantly increase earnings opportunities by keeping costs (e.g., operational expenses and capital expenditures) below amounts provided for in target revenues;

- New revenues from the sale of non-traditional products and services through planned Marketplace and other ongoing business development initiatives, ownership of historically jointly-owned utility poles, privatization of military utility system, electrification of transportation, and new opportunities to generate revenues with the innovative pilot framework adopted in this D&O; and

- The portfolio of PIMs and SSMs offered as part of the PBR Framework, as well as additional opportunities that may result from the post-D&O Working Group.[98]

In addition, as discussed in Section IV.A.2, infra, the new EPRM Guidelines explicitly include project expenses, in addition to capital expenditures, as eligible for recovery under the new EPRM, which may offer greater cost recovery for exceptional projects.

Further, the PBR annual review cycle, discussed in Section IV.E, infra, reduces the current structural lag in accrual of RBA rate adjustments to target revenues, which the Companies have identified as a contributor "to the inability to earn at or

[98]Currently, the Companies are subject to PIMs for Reliability and Call Center Performance. Under the PBR Framework, these PIMs will continue, and will be supplemented by a broader portfolio of new PIMs and SSMs, as described in Section IV.B, infra.

near the authorized return"[99] (as discussed, infra, the PBR annual review cycle not only reduces the revenue accrual lag, but also the revenue collection lag).

Regulatory safeguards incorporated into the PBR Framework will protect the Companies' financial integrity from extreme situations. If the Companies are unable to achieve the new incentives, and future earnings decline from historical levels, the ESM adopted in this D&O will ensure the Companies' financial integrity is not significantly jeopardized.[100] Further, the Re-Opener provision provides an additional layer of security as a catchall relief mechanism to address persistent, negative financial impacts.

In sum, the Commission has repeatedly affirmed its approach to PBR as including fundamental or transformational change. Basing the Companies' X-Factor on non-Hawaii jurisdictions that are not engaged in such change, are subject to different incentive and cost recovery mechanisms, and are not evolving toward more transformational PBR mechanisms strongly undercuts support for adoption of a proxy group-based X-Factor, particularly where that X-Factor is negative.

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[99]Hawaiian Electric RSOP at 76.

[100]See Consumer Advocate ISOP at 34-35.

Although Blue Planet's Binz Study avoids some of the concerns associated with the Companies' PEG Report, the Commission nonetheless finds that utilizing an X-Factor based on the Companies' existing index-driven revenue formula is preferable under the circumstances. Review of the Companies' historic performance under the existing RAM/RBA framework does not reflect unreasonable performance, and the Commission concludes that it provides a reasonable basis for assessing productivity to begin the transition to PBR, particularly given the additional revenue opportunities that will be available to the Companies, as well as the safeguards to protect them against extreme financial impacts.

iii.

Z-Factor

There is general consensus that an *ex post* Z-Factor is appropriate for inclusion in the ARA to address exogenous events not in the Companies' direct control.[101] While there has been further debate as to what qualifies as an "exogenous event,"

[101]See Hawaiian Electric ISOP at 108-09; Consumer Advocate ISOP at 41-42; Blue Planet ISOP at 15; "City and County of Honolulu's Phase 2 Initial Comprehensive Proposal First Update; Appendices A through C; Affidavit of Roy K. Amemiya, Jr.; Docket No. 2018-0088, filed January 15, 2020 ("C&CH January 2020 Proposal Update"), at 17; COH ISOP at 13; LOL RSOP at 5; and Ulupono ISOP at 30-31.

the Parties are in general agreement that such events are unanticipated, severe in impact, and not due to poor planning or negligence on behalf of the utility. Overlapping examples include changes in tax law (e.g., the recent 2017 Tax Cuts and Jobs Act), natural disasters, and the recent global COVID-19 pandemic.[102]

There is also general consensus that threshold limits are appropriate before Z-Factor relief may be sought.[103] In this regard, a number of Parties have adopted the Companies' proposed

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[102]See Hawaiian Electric ISOP at 109 (nonrecurring costs arising from a "catastrophic event or occurrence of a *force majeure* event[;]" alternatively, ongoing costs "resulting from accounting changes, or federal or state legislative, regulatory, or tax changes or new or modified State or federal mandates."); Consumer Advocate ISOP at 41 ("tax law changes, named storms and other catastrophic events exceeding a threshold dollar impact[,]" and "Federal and State declared emergencies[.]"); Blue Planet ISOP at 15 (expressing openness to accept "[b]eyond the paradigmatic example of a tax change . . . 'named storms, catastrophic events and other . . . declared emergencies[.]'"); C&CH January 2020 Proposal Update at 17 (citing as examples "tax laws, global capital market disruptions, or natural disasters."); COH ISOP at 13 (referring to "natural disasters or changes in federal tax and accounting law[,]" but excluding "costs incurred due to the Companies' failure to undertake reasonable precautions (i.e., disaster response planning, routine maintenance) ahead of time."); LOL RSOP at 5 (identifying "tax laws, natural disasters, and pandemics" as acceptable Z-Factor events); and Ulupono ISOP at 30-31 (referring to "hurricanes, volcanic eruptions, or other natural disasters . . . pandemics, changes in federal law (e.g., tax law) and other similar types of unforeseen and uncontrollable events.").

[103]See Hawaiian Electric ISOP at 112; Consumer Advocate ISOP at 42; Blue Planet ISOP at 15; and Ulupono ISOP at 37.

thresholds of $4 million per event for HECO and $1 million per event for HELCO and MECO.[104]

After reviewing the record and weighing the consideration raised by the Parties, the Commission adopts a Z-Factor that largely follows the consensus of the Parties. Specifically, the Z-Factor shall have the following characteristics:

- The Z-Factor shall begin with a neutral value, which may be adjusted in subsequent years depending on Commission approval of any requested Z-Factor relief by the Companies.

- Acknowledging the Companies' position that "the types of potentially eligible Z-Factor events should not be artificially constrained by preconceptions about what events may be exceptional circumstances not in the utility's direct control[,]"[105] the Commission declines to establish an exclusive list of Z-Factor exogenous events at this time, but will instead reserve discretion to evaluate Z-Factor requests on a case-by-case basis. However, the Commission cautions that it intends to abide by the general principles that the event must be exogenous to the utility and beyond the reasonable control of utility management.

- Further, Z-Factor relief will not be available to address changes to the Companies' ROE or

[104]See Hawaiian Electric ISOP at 112; Consumer Advocate ISOP, Exhibit 1 at 7 (proposing a $4 million Z-Factor threshold for HECO); and Ulupono ISOP at 37 (supporting the Companies' proposed thresholds of $4 million for HECO and $1 million each for HELCO and MECO).

[105]Hawaiian Electric RSOP at 141.

credit rating.[106] Not only would this be improperly characterized as an "exogenous event," but the Commission observes that such a situation is already addressed through the operation of the ESM and Re-Opener provisions of the PBR Framework, discussed in Section IV.D, infra.

- The Companies may file an application with the Commission to defer and/or seek recovery of costs (or how to address savings) associated with the Z-Factor event. The Commission may, on its own motion, instruct the Companies to submit a Z-Factor application.

The Commission notes that the above is largely consistent with the process proposed by the Companies.[107]

When reviewing the Companies' application for Z-Factor cost recovery, the Commission will utilize eligibility criteria drawn from the Companies' proposal:

1) The costs must be attributable to events outside the control of a prudently operating electric utility;

2) The costs must be related to the exogenous event and outside the base upon which the rates were originally derived;

3) The cost impact of the event must be clearly outside of the base upon which current effective rates were derived;

4) The costs must be prudently incurred;

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[106]C.f., Ulupono ISOP at 31 ("In particular, the Z-Factor should not be utilized in response to an actual or imminent credit downgrade resulting from the implementation of PBR mechanisms – such circumstances should be addressed through PBR Review, as discussed above.").

[107]See Hawaiian Electric ISOP at 113.

5) The costs must not be otherwise addressed by existing rates and/or other sources of cost recovery available to the utility (e.g., insurance, government aid, or indemnity from third parties); and

6) The costs related to each exogenous event must exceed the defined Materiality Threshold for the applicable utility [($4 million per event for HECO and $1 million per event for HELCO and MECO)].[108]

The Commission will use the above criteria to exercise its discretion to grant, deny, or modify the Companies' Z-Factor cost recovery requests, which will be reviewed on a case-by-case basis.[109]

iv.

Customer Dividend

As reflected in the Phase 1 D&O, the Customer Dividend has been described in this proceeding as a "stretch factor" incorporated into the ARA to "help ensure that 'day-one' savings

[108]Hawaiian Electric ISOP at 110.

[109]C.f., Consumer Advocate ISOP at 43 ("[T]he costs deferred for consideration as Z-factor adjustments should not be assumed fully recoverable from ratepayers and the Commission should consider other facts and circumstances in evaluating claims for Z-factor revenue adjustments . . . ."); and Blue Planet ISOP at 15 ("[T]he Commission should have the discretion to tailor the amount and timing of Z-Factor adjustments to the specific circumstances . . . .").

for utility customers are realized[.]"[110] The Phase 1 Staff Proposal further described the Customer Dividend as:

> . . .[A] feature to ensure that there is some "pay off" for customers. Since the annual change in revenues will nearly always be positive, a built-in [customer] dividend ensures that rates are lower than otherwise, even if they are increasing. This effectively serves as a "stretch factor" that challenges utilities to become more efficient than the productivity index (i.e., X-Factor).[111]

There have been a variety of CD proposals introduced during Phase 2 of this proceeding.

The Companies initially proposed a CD of 0.22%, which the Companies described as "the average stretch factor in current North America MRPs."[112] Subsequently, the Companies revised their CD proposal as a means to implement their Savings Commitment[113] (although the Commission conceptually approved the Savings Commitment as part of the HECO Rate Case Settlement, it did not approve any of the specific details or methods proposed by the

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[110]Phase 1 D&O at 31.

[111]Phase 1 Staff Proposal at 27.

[112]Hawaiian Electric ISOP at 71.

[113]See Hawaiian Electric ISOP at 72-73 and Exhibit B3. The Companies committed to $25 million in ongoing annual savings to be achieved over three years, with a split of 70/15/15% between HECO, MECO, and HELCO, respectively, with savings shared with customers the year after they are realized.

Companies, but reserved the right to determine these matters in this PBR proceeding).[114]

The Consumer Advocate proposes a CD based on the increase in revenue expected to result from the proposed acceleration of adjustments to annual target revenues, which would remove five months of accrual lag.[115] The Consumer Advocate notes that the expected January 1 commencement date of accrual of annual ARA adjustments will replace the existing June 1 accrual date under the existing RAM Provision. The Consumer Advocate estimates the value of revenues resulting from the expected accelerated accrual throughout the MRP and proposes passing four years' worth of the expected revenue increase to customers in the form of a one-time, "upfront" CD of $32,428,000 in the first year of the MRP.[116]

Ulupono supports either a 0.22% CD or the Consumer Advocate's one-time upfront CD proposal.[117]

The COH proposes a CD of "at least 4%," but expresses openness to implementing it in a "graduated" approach, such that

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[114]See D&O 37387 at 51-53.

[115]See Consumer Advocate ISOP at 39.

[116]See Consumer Advocate ISOP at 40 and Exhibit 2.

[117]Ulupono ISOP at 28. While proposing 0.22%, Ulupono also indicates that it would be comfortable with anything "in the range of approximately 20-30 basis points of the utility's authorized ROE."). Id.

the CD would start at 0% and increase annually during the MRP until reaching 4%.[118]

Blue Planet characterizes the CD as "basically a policy judgment by the Commission," and suggests "a placeholder value of 25 basis points[.]"[119] The C&CH recommend a CD value of "50 basis points (0.50 percent)," but submits that the CD should be determined "in the context of the X-Factor," and the "combined" X-Factor and CD should serve as "a calibrating mechanism for . . . the Commission [to] use its discretion to incentivize beneficial regulatory outcomes."[120]

As reflected above, there has been a wide range of proposed CD concepts and magnitudes, and the diverse nature of the proposals makes straight "apples to apples" comparisons difficult. For example, the CD proposals are derived from different premises and are expressed in different metrics; i.e., some are stated in dollar values and some in percentages or basis points of target revenues. Nonetheless, the Commission believes this spectrum of proposals reflects the flexible nature of the CD, and the diversity of opinions as to how best "share" the expected benefits of PBR with utility customers.

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[118]COH ISOP at 13-14.

[119]Blue Planet ISOP at 13.

[120]C&CH January 2020 Proposal at 16-17.

As noted by Blue Planet and the C&CH, the CD represents a policy judgment, and there is no specified methodology or well-established framework for determining a "correct" CD. Rather, the CD must be tailored to take into account the unique circumstances of the utility, its customers, and the complementary PBR mechanisms.

Taking all of this into consideration, the Commission has determined that the CD value in the MRP ARA formula will be reflected as a dollar amount that is based on the sum of two components: (1) a 0.22% annual compounded multiplicative factor; and (2) the annual $25 million Savings Commitment agreed to by Hawaiian Electric as part of the HECO Rate Case Settlement.

The 0.22% component of the CD factor will be applied to the portion of the Companies' annual ARA revenues that is subject to compounding. This annually compounding component of the CD is estimated to result in the following CD amounts over the MRP:

Table 3: Estimated Customer Dividend compounded over MRP ($ millions)[121]					
	2021	2022	2023	2024	2025
Combined Cos.	2.1	4.3	6.5	8.8	11.3
HECO	1.4	2.9	4.4	5.9	7.6
HELCO	0.3	0.7	1.1	1.5	1.9
MECO	0.3	0.7	1.1	1.4	1.8

This 0.22% component will be summed with the Savings Commitment arising from the Management Audit to form the annual CD factor of the ARA formula.

The Savings Commitment component of the CD will not be subject to annual compounding, but will consist of a predetermined amount representing the Companies' Savings Commitment to return to customers annual savings of $25 million on a steady state by 2023, based on the Management Audit's recommendations. The Commission has considered several different ways to reach this predetermined amount, as discussed below.

In the Companies' revised CD proposal, the $25 million Savings Commitment is first quantified on an annual "cash basis" ramping up in the years 2020 and 2021 to a steady annual amount of

[121]The values in this table represent estimates based on the Companies' existing target revenues, as reflected in Schedule B1 of their most recent RBA Tariff Transmittals. Actual values will be determined at the time the tariffs to implement the PBR Framework are approved and go into effect.

gross savings starting in the year 2022. These amounts are reduced by the "realization costs" incurred by the Companies in the years 2020 through 2022 to implement the savings measures. The net annual savings expressed on a cash basis reach $25 million in the year 2023 and remain at that amount in each subsequent year. The Companies then allocate the cash basis savings to "capital" and "O&M" categories and propose to return the capital portion, comprised of 80% of the total pledged savings, according to a revenue requirements analysis method based on a 31-year "service life." The Companies' proposal would thus result in a gradually increasing stream of annual amounts to be passed to customers that starts with zero in the year 2021 and reaches less than $14 million by the end of the MRP.[122]

Another method would be to utilize the "cash basis" savings streams identified in the Management Audit, as modified by the Companies, as the basis for implementing the Savings Commitment, which would use the "nominal value of savings generated by cost reduction activities[.]"[123] The annual amounts using this method are shown below in Table 4 (as noted above,

[122]See Hawaiian Electric ISOP, Exhibit B3 at 4-5; and Hawaiian Electric response to PUC-HECO-IR-2, filed July 9, 2020.

[123]See Hawaiian Electric ISOP, Exhibit B3 at 1 n.1.

this method results in a gradual increase each year, until 2023, when $25 million in benefits is achieved on a steady state basis).

Another consideration is whether to average or levelize the annual savings streams to "smooth" their impact over the years of the MRP. For the stream of identified net annual savings stated on a cash basis, a simple average of the amounts of savings identified in the five years of the MRP could be used in each year of the MRP. This would result in the Savings Commitment component of the CD being $22,156,000[124] in each year of the MRP. This would provide more substantial first-year savings to customers and would prevent the CD from increasing over the MRP.

Another alternative would be to utilize the revenue requirement streams identified by the Companies in their CD proposal, but levelize the revenue requirement projections over the 31-year "service life." This would recognize the Companies' approach, while accelerating realization of the Savings Commitment to a timeframe more contemporaneous with the Companies' achieved savings, and bring more meaningful savings to customers during the

[124]This amount is determined as a simple average of the total net annual savings for the combined Companies for the years 2021 thru 2025, identified in Hawaiian Electric's ISOP, Exhibit B3 at 1.

MRP. The levelized amount of the Companies' revenue requirements projections would be $23,289,000 in each year of the MRP.[125]

Table 4, below, depicts the various Savings Commitment CD amounts that would result from the alternatives discussed above:

Table 4: Alternative Savings Commitment Estimates ($ millions)					
	2021	2022	2023	2024	2025
Audit Cash Basis[126]	14.125	24.225	26.575	26.575	26.575
Cash Basis (Cos.)[127]	13.128	22.650	25.000	25.000	25.000

[125]This amount is determined by extension of the revenue requirement calculations provided by the Companies in response to PUC-HECO-IR-2, Attachment 1 through the entire 31-year "service life" period and determining nominal levelized amounts over 31 years using discount rates equal to the cost of capital used in the Companies' derivation of revenue requirements identified in HECO ISOP, Exhibit B3 at 4, for each Company.

[126]Source: Management Audit at 174 (section 18.5 "Savings Summary"), rounded to nearest $000,000. While the "Savings Summary" does not include a value for the year 2024, the savings of approx. $26.6 million achieved in 2023 are intended to be reflected on a "steady state basis" thereafter, meaning that they are expected to continue annually at this amount.

[127]Source: Hawaiian Electric ISOP, Exhibit B3 at 1 ("Savings Summary ($000)(Cash Basis)"). As noted in the preceding footnote, the achievement of approximately $25 million in annual savings in 2023 is expected to continue at a steady state thereafter.

While the Management Audit estimated that approximately $26.6 million in annual savings could be achieved by 2023, in the HECO Rate Case Settlement, the Companies agreed to a savings commitment of $25 million as a "more reasonable target to be achieved by the end of 2022." HECO Rate Case Settlement, Exhibit 1 at 31.

Cash Basis (Cos.): Averaged over MRP[128]	22.16	22.16	22.16	22.16	22.16
Rev. Req. Basis (Cos.)[129]	0[130]	2.091	8.649	11.145	13.562
Rev. Req. Basis (Cos.): Levelized over 31 Years[131]	23.29	23.29	23.29	23.29	23.29

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[128]Management Audit savings determined on a "cash basis" should be spread over a 5-year period, consistent with "returning" these benefits over the MRP.

[129]Source: Hawaiian Electric ISOP, Exhibit B3 at 4 ("Net Annual Savings Consolidated Revenue Requirement ($000s)").

[130]Hawaiian Electric's calculations reflect an estimated valueof ($1,515,000) for 2021 using the revenue requirement basis, arising from the offset in savings from "realization costs." Hawaiian Electric ISOP, Exhibit B3 at 4. However, Hawaiian Electric has clarified that during these years of "negative" Management Audit savings, the revenue requirement impact included in the proposed CD would be "$0." See Hawaiian Electric response to CA-HECO-IR-58(a), filed July 23, 2020; see also, Hawaiian Electric RSOP at 95-96.

[131]The levelization of Hawaiian Electric's revenue requirement amount is based on Hawaiian Electric's use of: (1) an "average service life" of 31 years to "depreciate" the Management Audit savings; and (2) the application of each of the Companies' respective cost of capital to determine the "revenue requirement" amount. See Hawaiian Electric ISOP, Exhibit B3 at 4; see also, Hawaiian Electric response to PUC-HECO-IR-3(h), filed July 9, 2020 (explaining the use of the 31-year service life).

Essentially, in calculating the "revenue requirement" amount for the Management Audit savings, the Companies spread out the return of the savings over a 31-year period and applied their respective costs of capital to those amounts. Accordingly, in levelizing this amount, the same 31-year period is utilized, and the same respective costs of capital were used to discount these extended payments into a levelized net present value.

After taking the above into consideration, the Commission finds that an averaged or levelized approach to returning the Management Audit savings pledged by the Companies is appropriate. In addition to providing a "smoother" return of the savings across the MRP, it also ensures that customers immediately receive and benefit from a meaningful portion of the Savings Commitment. In contrast, under a non-levelized-or-averaged approach, the Companies' Savings Commitment would not be substantially fulfilled in the MRP timeframe. For example, the Commission notes that under the Companies' revenue requirement approach, 80% of the Savings Commitment would be considered as a capital expense and would push realization of savings to customers far into the future. Realization of each year's $25 million annual savings by customers would not be fulfilled until the end of the 31-year service life assumed in the Companies' revenue requirements. For example, the annual net savings realized by the Companies in the first year of the MRP would not be fully realized by customers until the year 2051.[132] The Companies' approach also does not address the objectives established for the CD to provide "day-one" savings to customers.

[132] See Hawaiian Electric response to PUC-HECO-IR-2 at 9-11.

Turning to the scenarios presented in Table 4, above, the averaged cash basis ($22.16 million) and the levelized revenue requirement basis ($23.29 million) are relatively close in value and both approximate the "$25 million" in annual savings pledged by the Companies. Given the similar results, the Commission will adopt the lesser of the two, the "averaged cash basis," for use in the CD. This results in an annual Savings Commitment component of the CD of $22,156,000 for the combined Companies.

In terms of allocating the Savings Commitment impact to each of the Companies, the Commission adopts the "70%/15%/15%" allocation proposed by the Companies in their ISOP, under which 70% of savings are allocated to HECO and 15% each to HELCO and MECO.[133] This results in an annual Savings Commitment CD component of the CD of $15,509,000 for HECO; $3,323,000 for HELCO; and $3,323,000 for MECO, as reflected in Table 5, below:

Table 5: Estimated Savings Commitment (by Company): cash basis, averaged over MRP ($ millions)

	2021	2022	2023	2024	2025
Combined Cos.	22.16	22.16	22.16	22.16	22.16
HECO	15.51	15.51	15.51	15.51	15.51
HELCO	3.32	3.32	3.32	3.32	3.32
MECO	3.32	3.32	3.32	3.32	3.32

[133]See Hawaiian Electric ISOP, Exhibit B3 at 2.

When combined with the 0.22% compounded factor (Table 3, above), the resulting values for the combined CD are shown in Table 6, below:[134]

Table 6: Estimated 0.22% Compounded Dividend + $22.16 averaged Savings Commitment ($ millions)[135]					
	2021	2022	2023	2024	2025
Combined Cos.	24.2	26.4	28.7	31.0	33.4
HECO	16.9	18.4	19.9	21.4	23.1
HELCO	3.7	4.0	4.4	4.8	5.2
MECO	3.7	4.0	4.4	4.8	5.2

In reaching this conclusion, the Commission takes into account a number of considerations, including the following:

An annual compounded 0.22% Customer Dividend is supported in the record and proposed by several of the Parties as a reasonable "stretch factor." The Customer Dividend should represent a sharing of benefits expected to result from the PBR Framework. As described in the Phase 1 Staff Proposal, the Customer Dividend should "ensure that there is some 'pay off' for customers[,]" resulting from the annual index-driven ARA formula and "effectively serve as a 'stretch' factor that

[134]As noted in Table 3, above, the amounts of the 0.22% compounded component of the CD included in this table can only be estimated at this time.

[135]Figures in Tables 3 and 5 summed.

challenges utilities to become more efficient than the productivity index."[136] In this sense, the CD can be analogized to a "down payment" by the Companies on the efficiencies that are expected to accrue under the PBR Framework. As the Companies respond to the cost control incentives, their financial performance is expected to improve. It is important that some of these expected financial benefits flow back to customers, and the CD represents an immediate reduction to the Companies' revenues to effectuate this.

As stated by Hawaiian Electric, a 0.22% compounded CD represents the "average stretch factor in current North American MRPs[.]"[137] The Commission notes that this proposal was initially proposed by the Companies[138] and continues to be supported by Ulupono and LOL.[139] Further, this CD is very similar to the effective nature and amount of Blue Planet's suggested CD of 25 basis points of target revenues.[140]

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[136]Phase 1 Staff Proposal at 26.

[137]Hawaiian Electric ISOP at 70.

[138]See Hawaiian Electric ISOP at 71.

[139]See Ulupono ISOP at 28; Ulupono Second Proposal Update, filed May 13, 2020, at 19; and LOL ISOP (joinder to Ulupono Second Proposal Update and stating that LOL "fully supports Ulupono's position in its entirety.").

[140]See Blue Planet ISOP at 3 and 13.

Although other Parties, such as the COH and C&CH have proposed larger annually compounding CD values, the Commission does not believe they are warranted under the circumstances, given the Commission's decision to include the savings identified in the Management Audit Savings Commitment into the CD, which will increase the overall customer impact of the CD, as reflected in Table 6, above.

The Commission declines to adopt the Consumer Advocate's proposed CD. The Commission appreciates the Consumer Advocate's efforts in crafting a proposal that attempts to directly comply with the "day-one savings" approach articulated by the Commission. While the Consumer Advocate's proposal is intriguing, the Commission has concerns about the one-time nature of the proposal and the magnitude of the resulting variance in utility revenues and customer rates. "Front loading" the expected benefits of the PBR Framework into the initial year would result in a "lumpy" first year rate and revenue "reduction," where the full amount of the CD would occur, and which would then be followed by an "increase" of "no CD" in the following years, as opposed to a more even distribution across the MRP.

<u>The CD offers an opportunity for Hawaiian Electric to fulfill its pledge to pass through the Management Audit savings to customers identified in the recent HECO rate case.</u> In contrast to

new efficiencies incented under the PBR Framework, the Management Audit identified existing operational inefficiencies that should have been corrected prior to PBR. To the Companies credit, they embraced the Management Audit's findings and have quickly moved to begin implementing the Audit's recommendations,[141] including acknowledging $25 million in annual savings (achievable by the end of 2022) and pledging to return these savings to customers as part of the HECO Rate Case Settlement (i.e., the Savings Commitment).[142]

It is imperative that these savings be passed on to customers. The parties to the HECO Rate Case Settlement agreed that the issue of the Savings Commitment would be addressed in this proceeding, Docket No. 2018-0088.[143] In approving the HECO Rate Case Settlement, the Commission agreed that the issue of the Companies' Savings Commitment would be addressed in this proceeding, but clarified that it was not bound to adopt either

[141]See e.g., Management Audit at 188 (wherein the Companies state that the Management Audit's recommendations have served to accelerate efforts already underway). See also, id. at 190-204 (discussing specific measures being implemented).

[142]See HECO Rate Case Settlement, Exhibit 1 at 31-33.

[143]HECO Rate Case Settlement, Exhibit 1 at 33.

the Companies' or the Consumer Advocate's proposed treatment, "but may arrive at an independent solution."[144]

In their updated CD proposal, the Companies suggest using their commitment to share Management Audit savings to fulfill the purpose of providing a CD. However, the Commission is not persuaded that these savings, alone, sufficiently fulfill the role of the CD in the ARA, as contemplated by the Phase 1 D&O. As mentioned above, the Commission does not believe that the Management Audit savings reflect new efficiencies that will result from the PBR Framework. Rather, they represent a prior commitment from the Companies based on the HECO Rate Case Settlement to return a predetermined amount of savings to customers.[145] In recognition of this distinction, the Commission does not believe that the Savings Commitment, alone, can properly constitute a CD as envisioned for PBR, as they do not reflect any "stretch factor" to realize new efficiencies under the PBR Framework. Accordingly, while the Commission agrees with the Companies' proposal to use the CD to fulfill the HECO Rate Case Settlement Savings Commitment,

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[144]Docket No. 2019-0085, Decision and Order No. 37387 at 55.

[145]A primary reason for addressing the Management Audit savings in the context of PBR, rather than HECO's recent rate case, was in recognition that the audit savings benefits would be provided to customers after 2020; i.e., outside of HECO's rate case test year. See HECO Rate Case Settlement, Exhibit 1 at 33.

the Management Audit savings will be used to supplement the 0.22% CD discussed above to make up the total CD that will be applied to the ARA formula during the MRP.

As stated above, this averaged annual amount of Savings Commitment will be summed with a 0.22% compounding component to produce the total CD values set forth above and depicted in Table 6.

The Commission finds that this CD achieves the intent of the CD as envisioned in Phase 1, by incorporating a "stretch" factor to pass along the new efficiencies expected under the PBR Framework, in addition to providing a reasonable mechanism to implement the Companies' Savings Commitment. Further, the Commission observes that the financial impact of the CD will be offset by an expected reduction in expenses and attainment of some level of the PIMs and SSMs, which may be further supplemented by the efforts of the Post-D&O Working Group. Consequently, when taken in context of the overall PBR Framework, including the associated financial opportunities and safeguards, this CD is reasonable and should be implemented for the Companies.

v.

Calculating the ARA

While presented as a direct mathematical formula above, the Commission notes that the respective treatment of the various ARA factors requires some clarification. Although the formula as stated above provides for each factor to be combined arithmetically by addition and subtraction, some of the factors include multiplicative components that apply to previously determined revenue amounts, compounding annually, while other components are additive/subtractive in nature.

For the ARA formula to function properly, it must be clear how each factor is calculated and how it is applied. Thus, while the Commission does not adopt any specific tariff language or terminology at this time,[146] it provides the following clarifications:

- The ARA formula as stated above provides for each ARA factor to be combined arithmetically by addition and subtraction to determine a sum (the "ARA Adjustment") that will be added to the previous period's target revenues in the determination of effective target revenues.

- The portion of approved previous-year target revenue subject to escalation by the multiplicative factors in the ARA formula, and subject to accumulation and

[146]The development of specific tariff language will be the subject of a separate working group, as provided in Section IV.E.1, infra. The terminology used in the tariff language may differ from the terminology used herein.

compounding in future year ARA adjustments, will be referred to herein as the "compounded portion of the ARA Revenue."

- The initial amount of the compounded portion of the ARA Revenue shall be the electric sales revenue, minus fuel and purchased power expense from each Company's most recent general rate case, plus RAM Revenue Adjustments effective at the time the ARA-implementing tariffs take effect, with revenue taxes treated appropriately and consistently.

- The portion of approved previous year revenue that will be excluded from escalation by the multiplicative factors will be referred to as the "non-compounded portion of the ARA Revenue."

- The I-Factor shall be a term stated as a multiplicative percentage to determine an "I-Factor Amount" of revenue to be added in the ARA formula to determine the ARA Adjustment. The I-Factor percentage will be determined periodically based on the consensus forecasted annual change in GDPPI as published by the Blue Chip Economic Indicators as provided in the Implementation section of this D&O below. The I-Factor Amount of revenue to be included in the ARA Adjustment will be the I-Factor percentage multiplied by the previous year compounded portion of ARA Revenue. It is intended that the I-Factor Amount shall be included in the compounded portion of ARA Revenue to be included and escalated in future years. This is consistent with the I-Factor's purpose of allowing target revenues to annually adjust with the rate of inflation.

- The X-Factor shall be a term stated as a multiplicative percentage to determine an "X-Factor Amount" of revenue to be subtracted in the ARA Formula to determine an ARA Adjustment. The X-Factor Amount of revenue to be subtracted in the ARA Adjustment will be the X-Factor percentage multiplied by the previous year compounded portion of ARA Revenue. It is intended that the X-Factor Amount shall be included in the compounded portion of ARA Revenue to be included and escalated in future years. This is consistent with the X-Factor's purpose of incorporating incremental improvements in productivity.

- The Z-Factor shall be a term stated as an amount of revenue specifically approved by the Commission to be added in the ARA Formula to determine an ARA Adjustment. The "Z-Factor Amount" of revenue shall be included in the non-compounded portion of ARA Revenues and shall not be subject to escalation, accumulation, or compounding by the multiplicative factors in the ARA formula. Notwithstanding the provisions stated immediately above, the Commission may establish specific terms for the form, amount, duration, and application of Z-Factor Amounts at the time the Commission approves Z-Factor revenue. This is consistent with the Z-Factor's purpose of providing *ad hoc* relief in response to a particular event outside of the Companies' control that is unique and finite (i.e., non-recurring) in nature.

- The 0.22% "multiplicative" component of the CD shall be a term stated as a multiplicative percentage to determine the "Multiplicative CD Component Amount" of revenue to be subtracted in the ARA Formula to determine an ARA Adjustment. The Multiplicative CD Component Amount of revenue to be subtracted in the ARA Adjustment will be the component percentage multiplied by the previous year compounded portion of ARA Revenue. It is intended that this amount shall be included in the compounded portion of ARA Revenue to be included and escalated in future years. This is consistent with the "stretch factor" aspect of the CD, which is intended to continually "challenge the utility to become more efficient than the productivity index (i.e., X-Factor)."

- The "subtractive" Savings Commitment component of the CD, "Subtractive CD Component Amount," is to be an annually specified amount of revenue specifically determined by the Commission to be subtracted in the ARA Formula to determine the ARA Adjustment. The Subtractive CD Component Amount of revenue shall be included in the non-compounded portion of ARA Revenues and shall not be subject to escalation, accumulation, or compounding by the multiplicative factors in the ARA formula. This is consistent with the Companies' Savings Commitment to return the identified $25 million in Management Audit savings to customers, which are expected to be achieved on a steady state basis. As this is intended to reflect a pass-through of the

> Management Audit's identified savings, escalation through the ARA Formula would not be appropriate.

The Commission notes that this is generally consistent with the ARA calculations proposed by the Companies.[147] The final tariffs implementing the PBR Framework should carefully and clearly reflect the intent of the clarifications above to avoid confusion during the annual determinations of the ARA factors, ARA Adjustment, and resulting effective target revenue.

4.

Modifications to the MPIR Guidelines

As stated in the Phase 1 D&O, within the PBR Framework, "[t]he MPIR adjustment mechanism will continue to provide revenues for extraordinary projects as approved by the [C]ommission, above revenues established by the ARA."[148] Currently, the MPIR serves as a relief mechanism for capital expenditures for extraordinary projects in excess of the Companies' annual index-driven revenue cap (i.e., the "RAM Cap"). As the Companies transition into the PBR Framework, "[t]he [C]ommission agrees that preserving the MPIR

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[147] See Hawaiian Electric response to PUC-HECO-IR-32, filed September 17, 2020, Attachment 1 at 3 (describing the I-Factor and X-Factor as the "Recurring Adjustment Component" and applying them target revenues prior to the Z-Factor) and 9 (providing fixed figures of Management Audit amounts to be applied in specific years).

[148] Phase 1 D&O at 33.

adjustment mechanism for extraordinary projects is appropriate, to the extent that it may not be feasible to effectively address all such investments during the MRP period exclusively through an externally-indexed revenue formula."[149] However, the Commission noted that Phase 2 offered the opportunity to consider revisions to the MPIR "to address capital bias that may be perpetuated through the current MPIR adjustment mechanism and explore how the MPIR may be used to address incentives regarding capital expenditures and operational expenditures."[150]

In the Phase 1 D&O, the Commission observed that continuation of the MPIR, conceptually, was largely favored by the Parties, subject to discussion about its ongoing applicability and scope.[151] Throughout the Working Group Process and the Briefing Process, the Parties have continued to support the existence of the MPIR, though they have proposed a range of modifications that would restrict or, under the Companies' proposal, enlarge, the MPIR's scope. In general, the Companies have proposed the broadest expansion of the MPIR to explicitly

[149]Phase 1 D&O at 34.

[150]Phase 1 D&O at 34-35.

[151]Phase 1 D&O at 34 (citing "Division of Consumer Advocacy's Reply Statement of Position on Staff Proposal for Updated Performance-Based Regulation," filed April 5, 2019, Exhibit 1).

encompass new categories of costs and expenses,[152] while other Parties propose continuing to restrict the MPIR to extraordinary projects, with minor modifications to the existing MPIR Guidelines.[153]

Upon review, the Commission continues to believe that relief for exceptional projects, as currently provided pursuant to the MPIR, should continue as part of the PBR Framework. Certain projects represent "lumpy" investments that may not be considered "business as usual" costs manageable under annual revenues derived from an index-driven revenue formula, and MPIR-like relief may be appropriate to address such projects, subject to Commission approval. That being said, the Commission recognizes that excessive use of such extraordinary relief would dilute the cost control incentives of the ARA. As a result, the Commission will limit approval to "exceptional" projects,

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[152] See Hawaiian Electric ISOP at 83 (MPIR relief for "equipment or facilities for new developments or unserved areas or to serve growth in an area, projects for resiliency and re-powering projects, and telecommunications equipment and infrastructure projects") and 87 (proposing MPIR recovery to include not only capital project costs, but costs related to appropriate service contracts, software development projects, and resilience projects, and utility-scale generation and energy storage). See also, Ulupono ISOP at 47-48.

[153] See Consumer Advocate ISOP t 76-78; Blue Planet ISOP at 46; and COH ISOP at 11.

as determined on a case-by-case basis, consistent with the Commission's current practice.

After considering the suggestions and concerns raised by the Parties, the Commission concludes the MPIR Guidelines can remain largely intact, with relatively few substantive modifications. As a preliminary matter, the Commission will change the title of the MPIR to the "Exceptional Project Recovery Mechanism," in recognition that relief under this mechanism: (1) is no longer limited to "major projects" (a term that specifically encompasses capital expenditures), but will be eligible to other project costs, such as O&M expenses; and (2) the concept of "interim" relief is not consistent with the nature of the MRP, which does not contemplate general rate cases during its operation.

That being said, the general purpose of the MPIR will remain,[154] and, consistent with the PBR guiding principle of administrative efficiency, the Commission has avoided

[154]C.f., Blue Planet ISOP at 44 ("The basic purpose of MPIR, therefore, should not fundamentally change: that purpose, now and going forward, is to allow recovery of revenue requirements for extraordinary, 'lumpy,' major projects that are not incorporated within the index-driven baseline."); and Consumer Advocate ISOP at 75-76 (suggesting transferring the MPIR into tariff form, but "reiterating most of the definitions, eligibility and filing requirements from the existing MPIR Guidelines, with the addition of an "Evaluative Criteria.").

incorporating additional and/or unnecessarily complex steps to the new EPRM review process.

Accordingly, while the Commission appreciates the robust discussion and range of modifications proposed by the Parties, the Commission will not incorporate monetary threshold requirements, expansive new definitions, or additional stakeholder review requirements to the EPRM Guidelines. While representing valuable considerations, the addition of too many requirements and strictly-defined terms and concepts may inadvertently hinder the efficacy of the EPRM by creating confusion as to the potential eligibility of a proposed EPRM project, limiting the Commission's discretion to review and approve EPRM applications, and/or increasing the time and resources associated with review of EPRM applications.

Instead, the Commission concludes that the more prudent course of action, in keeping with the EPRM's intent to limit relief to only exceptional projects, is to establish broader principles that are then applied by the Commission on a case-by-case basis. This will allow the Commission to take into account the unique circumstances of a particular application, which may reflect conditions that are unforeseen or unknowable at this time.[155]

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[155] C.f., Blue Planet ISOP at 50 ("Beyond such conceptual guides . . ., it may not be practical or productive to attempt to

In reaching this conclusion, the Commission has taken into account several considerations, including the following:

- Attempting to incorporate precisely crafted definitions and criteria may inadvertently exclude otherwise worthy extraordinary projects from EPRM eligibility.

- Similarly, implementing new monetary thresholds may unintentionally divert focus away from the nature of the proposed project towards its size and/or cost. The Commission emphasizes that it is the extraordinary nature of the project that is dispositive; projects that are merely large or costly, without appropriate purpose or justification, are not suitable for EPRM relief.

- Further, limiting EPRM eligible projects to pre-determined plans made in other dockets may limit the flexibility to address unforeseen events or take advantage of unexpected opportunities (e.g., improvements in technology, changes in consumption behavior, etc.).

- Expressly allowing operating expenses to be eligible for EPRM relief will help mitigate the bias toward capital expenditures that might otherwise exist under the current MPIR Guidelines' focus on capital expenditures.

- Continuing to review the Companies' EPRM requests through a separate docket proceeding balances the interests of timely reviewing the Companies' requests with opportunity for input from interested stakeholders. Reviewing individual EPRM requests in the context of a single docket (e.g., IGP) may result in confusion and delay arising from the intermingling of issues and procedural considerations. Utilizing a

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manufacture a more complex, encyclopedic definition to cover all the possible situational permutations for what constitutes 'baseline' versus 'exceptional' revenues. In short, context is key, and a 'case by case' inquiry is necessary, as the MPIR Guidelines expressly acknowledge.").

separate docket will allow the Commission to focus on only those issues pertinent to the EPRM request. To the extent stakeholders would like to be involved, the Commission's rules provide opportunities to seek intervention or participation in a Commission proceeding.

- Allowing the Companies to include the full amount of approved costs in the EPRM for recovery during the first year the project will support utility financial integrity. Combined with the PBR Framework's annual review cycle, discussed in Section IV.E.3, infra, this cost recovery structure will allow for more timely collection of approved EPRM revenues.

Consistent with the above, the Commission provides the following principles that it will utilize in determining whether to approve EPRM relief:

- Requests for EPRM relief shall be made by separate application and will be reviewed by the Commission on a case-by-case basis.

- In reviewing a request for EPRM relief, the Commission retains discretion to grant relief in full or in part, or to deny the request in its entirety.

- Costs recovered through the EPRM shall not be duplicative of costs otherwise recovered through the ARA, PIMs, SSMs, or other cost recovery mechanisms.

- EPRM relief should be sought sparingly, and shall be reserved for projects which are extraordinary in nature and do not reflect "business as usual" investments or expenses.

- In certain instances, EPRM relief may be appropriate for projects or programs previously reviewed by the Commission and prospectively found to be extraordinary or worthy of EPRM relief.

- EPRM relief should not perpetuate bias toward capital expenditures.

- The EPRM should not be used as a means to circumvent the ARA or other cost control incentives of the PBR Framework.

The Commission notes that many of these principles are already reflected in the existing MPIR Guidelines,[156] underscoring the practicality of preserving the Guidelines with appropriate revisions. Accordingly, only a few modifications to the MPIR Guidelines have been necessary to produce the new EPRM Guidelines, including the following:

- Expressly providing that in addition to capital costs, expenses are eligible for EPRM relief.

- Clarifying that requests for EPRM relief for expenses will be made by separate application for review and approval by the Commission. Consistent with the current General Order No. 7 limits for capital expenditures, non-capital expenses must be over $2.5 million to warrant EPRM consideration.

- Permitting the Companies to include the full amount of approved costs in the EPRM for recovery in the first year the project goes into service, pro-rated for the portion of the year the project is in service.

- Removing explicit permission to "group" small projects below $2.5 million in order to qualify for EPRM consideration. While it still may be appropriate, under certain circumstances, for smaller projects to be considered as a "single" project for purposes of EPRM relief, this will no longer be explicitly permitted and the Commission will review such requests on a case-by-case basis to determine if consideration for EPRM relief is appropriate.

[156]See Order No. 34514, Attachment A ("MPIR Guidelines").

- Miscellaneous revisions to account for changes in terminology and implementation details related to the PBR Framework.

A copy of the Commission's EPRM Guidelines is attached as Appendix A to this D&O (redlines to the existing MPIR Guidelines are included as Appendix B).

Accordingly, the MPIR Guidelines are terminated as of the date of this D&O and immediately replaced with the EPRM Guidelines, with the exception that any pending application for MPIR relief submitted by the Companies prior to this D&O will be grandfathered under the MPIR Guidelines. If the Companies wish for a pending MPIR application to be reviewed under the EPRM Guidelines, they must make an affirmative written request in the appropriate docket. This may require the submission of supplemental materials, as may be required under the EPRM Guidelines.

Notwithstanding the above, the Commission retains the authority to re-examine the EPRM and the EPRM Guidelines at any time, including making changes to the Guidelines or adjustment mechanism itself, if the Commission determines that it is not operating as intended.

5.

Existing Cost Recovery Mechanisms

In the Phase 1 D&O, the Commission confirmed that "[e]xisting cost trackers and pass-through mechanisms will continue to operate [during the PBR Framework.]"[157] In general, this has not been opposed by the Parties,[158] although some have proposed modifications to the ECRC.[159]

Upon review of the record and circumstances, the Commission finds that allowing the Companies' existing cost trackers and pass-through mechanisms (e.g., ECRC, PPAC, pension and OPEB trackers, REIP surcharge, DSM, DRAC, etc.) to continue without modification is reasonable. In support thereof, the Commission notes that these existing trackers currently recover costs that are not reflected in current effective rates and, thus, will not be addressed through ARA Revenues. Eliminating or modifying them at this time may result in unintended consequences. That being said, the Commission will continue to monitor these trackers and pass-through mechanisms, and reserves

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[157]Phase 1 D&O at 36.

[158]See Hawaiian Electric ISOP at 42; Consumer Advocate ISOP at 78; and Ulupono ISOP at 53.

[159]See Blue Planet ISOP at 54-56; Consumer Advocate RSOP at 136; and C&CH ISOP at 3.

the right to initiate review and potential modification of any such mechanism.

Additionally, the Commission observes that Parties have only raised concerns with the ECRC. Given the other PBR mechanisms designed to incent the Companies to pursue cost control and integrate greater amounts of renewable energy, it is expected that the Companies' fossil fuel consumption may be addressed through those means. Further, as discussed below, the PBR Framework includes a Post-D&O Working Group to continue developing Performance Mechanisms, which may result in additional PIMs and/or SSMs intended to reduce the Companies' fossil fuel consumption.

B.

Additional Revenue Opportunities

As noted above, the ARA is intended to provide Hawaiian Electric with reasonable annual operating revenues, while incenting cost control and providing an opportunity to increase earnings through the nature of its index-driven revenue formula. However, additional financial opportunities will be available to the Companies through a portfolio of Performance Mechanisms, including PIMs and SSMs, as detailed below.

PIMs and SSMs play a critical role in the PBR Framework. As noted above, they represent additional opportunities for the

Companies to earn revenues and improve their financial position. Their role is intrinsically tied to that of the primary revenue adjustment component, the ARA, and is 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.

In general, the Commission has focused on developing PIMs utilizing "Outcome-based" metrics, as opposed to "Activity-based" or "Programmatic-based" metrics.[160] As noted in Staff Report #3, Outcome-based metrics "can allow utilities to determine the most effective strategy to achieve policy objectives . . . while somewhat relieving regulators from dictating program terms."[161]

Accordingly, most of the PIMs included in the PBR Framework are Outcome-based, which incent direct progress toward specific outcomes, while leaving to the Companies' discretion the specific means by which they can reach the specified targets. However, the Commission also finds value in developing

[160]See Letter From Commission To: Service List Re: Staff Report #3 - Docket No. 2018-0088, In re Public Utilities Commission, Instituting a Proceeding to Investigate Performance-Based Regulation, filed November 14, 2018 ("Staff Report #3"), at 18-20.

[161]Staff Report #3 at 19.

a few Activity-based and Programmatic-based PIMs, as the Companies gain experience with operating under incentives tied to some of the "emergent" Outcomes.

Relatedly, the Commission has focused on developing PIMs to incent progress towards "emergent," rather than "traditional" Outcomes.[162] The Commission notes that it currently has in place several PIMs incenting "traditional" outcomes, such as service reliability, and that other PBR mechanisms, such as the ARA, address other "traditional" outcomes, such as cost control. Accordingly, the PIMs approved herein and prioritized for near-term development by the Commission focus on "emergent" outcomes, both to balance the Outcomes incented under the PBR Framework, as well as in recognition of the need to emphasize the importance of the role of "emergent" outcomes "as Hawaii progresses towards a 100% RPS, as the electricity system becomes more renewable and distributed, and as the [Companies] pursue opportunities for non-traditional outcomes[.]"[163]

In addition to the Performance Mechanisms approved in this D&O, the PBR Framework will include a Post-D&O Working Group where the Parties can continue to examine other PIM and SSM

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[162]See Phase 1 Staff Proposal at 16.

[163]Phase 1 Staff Proposal at 16.

proposals during the MRP. PIMs and SSMs may also be considered in other Commission proceedings focused on supporting the Goals and Outcomes established in this docket. In the event a PIM or SSM is satisfactorily vetted and developed, the Commission will consider approving it for implementation during the MRP.[164]

1.

Performance Incentive Mechanisms

In the Phase 1 D&O, the Commission expressed its desire to prioritize development of "three to six new PIMs addressing the specific Outcomes of *Customer Engagement, DER Asset Effectiveness*, and *Interconnection Experience*."[165] During the Working Group Process, a number of PIMs addressing these Outcomes were discussed and vetted by the Parties, and throughout the Briefing Process, the Commission has continued to solicit feedback on a number of PIM concepts addressing these Outcomes. Ultimately, after robust

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[164]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.

[165]Phase 1 D&O at 11 and 45 (citing Phase 1 Staff Proposal at 34) (emphasis in the original). The emphasis on "new" PIMs is to distinguish them from the existing PIMs addressing the Companies' performance in the areas of reliability and Call Center Performance. Id. at 45-46.

discussion and extensive effort by the Parties and Commission, the Commission has determined that the PBR Framework will begin with the following PIMs intended to primarily address *Interconnection Experience*, *DER Asset Effectiveness*, and *Customer Engagement*.

i.

Interconnection Approval PIM

This PIM is intended to promote the PBR Outcome of *Interconnection Experience* by incenting the Companies to reduce the total interconnection time for systems under 100 kW, and will feature both "upside" and "downside" components.[166]

- Metric: The metric will be the mean (average) number of business days it takes the Companies to complete all steps within the Companies' control to interconnect DER systems <100kW in size, in a calendar year. The PIM will be applied to each of the Companies' performances, respectively. The average time will be adjusted to remove outliers for interconnection times outside two standard deviations above the mean (the "adjusted average").

- Targets/Incentives: this PIM will offer three tiers of targets to earn financial rewards and three tiers of targets that will incur financial penalties.

    - **Upside targets** are at or above the annual thresholds included in the table below, with corresponding financial rewards.

[166]See Phase 1 D&O at 49.

Table 7: Interconnection Approval PIM Reward Targets *Targets shown in average number of business days with outliers excluded					
Thresholds and Potential Reward Level	**2021**	**2022**	**2023**	**2024**	**2025**
TIER 1: +$1,050,000 HECO +$225,000 HELCO/MECO	21	18	15	12	9
TIER 2: +$700,000 HECO +$150,000 HELCO/MECO	24	21	18	15	12
TIER 3: +$350,000 HECO +$75,000 HELCO/MECO	27	24	21	18	15

- 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.

- Rewards among tiers are cumulative; e.g., financial rewards the Companies earn for meeting a "Tier 2" target would be additive to a reward for meeting a "Tier 3" target.

- The annual maximum award is $3 million for all of the Companies, calculated on a target revenue basis (70/15/15 split for HECO/HELCO/MECO). For HECO, this adds up to a maximum annual incentive of $2,100,000; for HELCO and MECO, this adds up to a maximum annual incentive of $450,000.

- **Downside targets** should be at or below the annual thresholds included in the table below, based on the Companies' current performance, with corresponding financial penalties.

- At this time, the Commission provides proposed penalty thresholds, but will allow the Post-D&O Working Group to consider this issue and propose alternative penalty thresholds for this PIM.

Table 8: Proposed Interconnection Approval PIM Penalty Thresholds *Targets shown in average number of business days with outliers excluded					
Proposed Thresholds and Potential Penalty Level	**2021**	**2022**	**2023**	**2024**	**2025**
TIER 1: -$315,000 HECO -$67,500,000 HELCO/MECO	42	39	36	33	30
TIER 2: -$210,000 HECO -$45,000 HELCO/MECO	39	36	33	30	27
TIER 3: -$105,000 HECO -$22,500 HELCO/MECO	36	33	30	27	24

- o These thresholds should resemble the tiered rewards targets outlined above, based on fixed day thresholds, with outliers removed.
- o Thresholds should be consistent for all three Companies to ensure timeliness of DER interconnection across service territories and removing outliers maintains consistency with the reward structure and does not penalize the Companies for extreme situations.
- o Penalties among tiers are cumulative; e.g., penalties incurred for reaching a "Tier 2" penalty would be additive to a penalty for reaching a "Tier 3" threshold.
- o The annual maximum penalty will be set for $900,000 for all 3 Companies, calculated on a target revenue basis (70/15/15 split for HECO/HELCO/MECO).

- Duration: this PIM will be set for three (3) years, after which the metrics, targets, and incentives will be re-evaluated.

The underlying structure of this PIM (incenting improved interconnection times for DER systems <100 kW) was initially proposed by the Companies[167] and builds on efforts already underway at the Companies.[168] The Companies have also clarified that they do not anticipate a cost impact to non-participating customers related to incremental efficiencies gained through improved interconnection processes using existing resources.[169]

In refining this PIM to its approved state, the Commission took into account a number of considerations. Regarding the metric, the Commission observes that using the number of elapsed days during the interconnection process has not been conceptually challenged or opposed by the Parties. Unlike the Companies' proposal, though, this PIM will measure the days taken to complete steps within the Companies' control, rather than days to issue conditional approval.[170] As noted by certain Parties, focusing on conditional approval limits the PIM's scope to "only one initial segment in the existing interconnection process," and ignores the "many additional sequential utility process steps

[167]Hawaiian Electric ISOP at 194-95.

[168]See Hawaiian Electric RSOP at 235-35 (referencing In re Public Util. Comm'n, Docket No. 2019-0323).

[169]See, Hawaiian Electric response to PUC-HECO-IR-20(c), filed August 11, 2020.

[170]See Hawaiian Electric ISOP at 194-95.

. . . [which] often stretch[] over many months, until customers can finally energize and interconnect their DER systems."[171]

Accordingly, the Commission is approving a PIM that utilizes a metric that measures days to complete steps within the Companies' control during the interconnection process. Based on the Parties' IR responses, this PIM will define "days within the Companies' control" as: "those discrete steps in the interconnection process where the utility is required to take action and needs no further materials or information from the DER customer to take such action."[172] Notwithstanding that the Companies have identified those steps within the interconnection

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[171]Blue Planet ISOP at 74. See also, Hawaiian Electric ISOP at 194 n.220 (stating that "Under the Company's standard process, when a customer receives Conditional Approval, they are approved to build or install their PV system, but should not turn it on yet. The customer receives permission to turn on their PV system after subsequent conditions are met.").

See also, Blue Planet response to PUC-Parties-IR-09(h), filed September 17, 2020 ("This proposal clearly improves on the Companies' proposal, by seeking to address the interconnection timeframe in its entirety, rather than just the initial, limited, and artificial step of "conditional approval[.]");

[172]DER Parties response to PUC-Parties-IR-09(c), filed September 17, 2020. See also, Blue Planet response to PUC-Parties-IR-09(c) ("Blue Planet believes the DER Parties offer a workable definition . . . "); and Hawaiian Electric response to PUC-Parties-IR-09(c), filed September 17, 2020 ("'Steps within the Companies' control should be defined as any period of time when a customer's application is waiting for utility action in the interconnection process.").

process that they maintain are within their control,[173] this definition will be controlling for purposes of implementing this PIM. Relatedly, the Commission had considered relying on Rule 14H to develop a working definition for this PIM, but has decided that its foundation in the existing interconnection process may not render it appropriate as a metric as the interconnection process evolves.

The Commission finds this metric to be suitable for addressing the *Interconnection Experience* Outcome. The time and/or delays associated with processing an application to interconnect a customer's DER system is one of the most prominent and memorable aspects of the interconnection process. Reducing the average time to complete the interconnection steps within the Companies' control will directly improve customers' experience by allowing them to more immediately benefit from their DER system investment, as well as facilitate a more efficient integration of DERs onto the Companies' system.

The use of the mean (average) number of days to interconnect is calculated to provide a more representative reflection of the Companies' performance. While the Companies proposed using the median, rather than mean, number of days over

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[173] See Hawaiian Electric response to PUC-HECO-IR-45(a), filed September 17, 2020.

a year,[174] the Commission agrees with the concerns raised by Consumer Advocate regarding use of the median number of days:

> While the Companies raise valid concerns about relatively uncommon outlier applications, this concern does not outweigh the imperative of ensuring that all stages of the interconnection process, for all candidate systems, are handled expeditiously by the Companies. Using a median measure effectively provides cover to the Companies to neglect nearly half of all applications. As an illustrative example, the Companies could earn their proposed incentive even if conditional approval on 49% of all applications for systems <100 kW took one year to complete. Even with the proposed symmetry of possible penalties . . ., using the median performance could allow the Companies to focus on only the easy projects to achieve the reward and lessen the focus on the projects that fall out of the median band since the risk to leave the projects outside of the median is negligible.[175]

[174]See Hawaiian Electric response to PUC-Parties-IR-09(a).

[175]Consumer Advocate response to PUC-Parties-IR-09(a), filed September 18, 2020. See also, Ulupono response to PUC-Parties-IR-09(a), filed September 17, 2020 ("Notwithstanding the foregoing, using a mean rather than a median number of days as the standard would be a higher standard of performance and likely more beneficial to those waiting for DER interconnections than a median standard. Ulupono would recommend that outliers be handled by shaving off or throwing out the most extreme outliers in these calculations."); and COH response to PUC-Parties-IR-09(h), filed September 16, 2020 ("By removing the outlier cases (those fast and slow) and using the median/average time of interconnection, the proposal incentiv[izes] the Companies' [sic] to more evenly distribute efforts to enhance interconnection for all applicants.").

However, in recognition of the Companies' concerns about the impact of "outliers" on their measured performance, the Commission has incorporated the Consumer Advocate's suggestion of "excluding outliers from the calculation of the mean[,]" by excluding applications whose times fall outside two standard deviations above the mean. This should mitigate concerns that anomalous applications will negatively affect the Companies' performance under this PIM, but still allow the Companies to benefit from those instances where interconnection times were exceptionally fast.

Regarding the targets, these 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.[176]

Regarding incentives, the maximum "upside" rewards are capped at $3 million annually, allocated on a 70/15/15 split across the Companies (this allocation is based on the Companies' proposed

[176]See Hawaiian Electric response to PUC-HECO-IR-54, Attachment 1, filed November 17, 2020. The Commission notes that the Companies provided an estimated average of 36 business days in processing applications for all steps under their control for the calendar year 2019 (including HECO, HELCO, and MECO). See Hawaiian Electric response to PUC-HECO-IR-20 at 2.

allocation of the Management Audit savings).[177] The "downside" penalties are capped at $900,000 annually, and similarly allocated across the Companies on a 70/15/15 basis.

The Commission considered the Companies' suggestion to lower the $1 million penalty amount proposed in PUC-Parties-IR-09 to "allow the Companies to gain familiarity with the PIM" and to experiment with improvements "at a lower risk to start."[178] In response, the Commission has lowered the penalty amount to $900,000 and has incorporated regressing tiers to provide a reasonable opportunity for the Companies to adjust to this PIM without being severely penalized. The tiered nature of the penalty structure also mitigates the financial impact to the Companies, by penalizing poorer interconnection performance in a progressive fashion, rather than imposing the entire penalty based on a single threshold. Combined with the potential rewards (up to $3 million, annually), this PIM's incentives should reasonably motivate the Companies to strive for continued improvement in their interconnection processes on an ongoing basis.

Further, the Commission will provide the Post-D&O Working Group with the opportunity to further consider

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[177]See Hawaiian Electric ISOP, Exhibit B3 at 2.

[178]Hawaiian Electric response to PUC-Parties-IR-09(g).

the issue of an appropriate penalty threshold for this PIM. Although 36 days is reflective of the Companies' 2019 practices and may serve as a penalty threshold, a significant amount of interconnection data was recently produced in response to Commission IRs that includes the number of days for various steps in each of the Companies' interconnection processes for systems that were interconnected between 2018 and October 2020. The Post-D&O Working Group may be interested in disaggregating and analyzing this data to determine whether an alternative penalty threshold may be more appropriate.

The Commission understands the Companies' concerns related to a number of circumstances that might impact their eligibility for a reward or penalty under this PIM, but declines to adopt the Companies' proposed "guardrails" at this time.[179] The removal of outliers from the PIMs calculation should help address concerns related to hosting capacity, and force majeure events will be considered on a case-by-case basis. Further, the Commission restates its intention that this PIM apply to all systems <100kW and does not find excluding CBRE or SIA projects <100kW reasonable at this time.

[179]See Hawaiian Electric ISOP at 195-96.

The Commission is not convinced of the need to exclude customers who want to sign up for DR programs, given that customer interest in participating in DR programs should not impact the timely interconnection of DERs. Similarly, the Commission is not persuaded that a cap on the total volume of applications in a given calendar year is appropriate to establish at this time, but will reassess whether or not a cap may be necessary during subsequent annual reviews.

The Commission notes that the PIM rewards and penalties are not tied to Rule 14H as previously contemplated, but is open to reassessing this PIM in the event the Companies make relevant modifications to Rule 14H timeframes.

Ultimately, as noted in Section IV.E.3, infra, the Commission will be reviewing all of the PIMs as part of an annual review cycle and, further, there are a number of safeguard mechanisms that allow the Commission to review and modify any of these PBR mechanisms as appropriate, in the event they are not operating as intended.

In sum, upon careful review of the record and weighing the considerations raised by the Parties, the Commission finds the above-described PIM to be reasonable and consistent with the "PIM-specific design considerations" identified in the

Phase 1 D&O,[180] including: utilizing a quantitative standard to measure performance; balancing performance risk to the Companies with the opportunity to earn financial incentives; incorporating a target based on actual, incremental improvement; providing three tiers of additive financial incentives to reward outstanding performance; and scheduling review of the PIM on an annual basis, to address any unintended consequences in a timely manner.

ii.

Grid Services PIM

This interim PIM is intended to promote the PBR Outcome of *DER Asset Effectiveness*, as well as *Grid Investment Efficiency*, by incenting the Companies to expeditiously acquire grid service capability from DERs ("Grid Services PIM"). This PIM will be "upside" only; i.e., featuring financial reward opportunities, but no penalties.[181] While initially focusing on the acquisition of grid services from DERs, this PIM is intended to be replaced during the MRP with a refined PIM that incents utilization of DERs for grid services, upon determination of appropriate metrics and

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[180] See Phase 1 D&O at 43-44.

[181] See Phase 1 D&O at 49.

identification of required data to measure how DERs are being utilized to meet system needs.

- Metric: the metric will be kW capacity of grid services acquired by the Companies or by program between January 1, 2021, to December 31, 2022. Eligible grid services include Fast Frequency Response ("FFR"), load build, and/or load reduction. The scope of grid services eligible for this PIM will be grid services acquired with approval by the Commission to broadly include, but not be limited to: (1) measures and programs approved in the DER docket; and (2) innovative measures or new concepts proposed by the Companies.

- Target: Unlike the other PIMs included in the PBR Framework, this PIM does not feature a target. This reflects the PIM's intent to address the recent shortfall in the Companies' grid services procurement efforts, which were themselves attempting to reach specific pre-determined levels. Rather than set new aspirational targets, the PIM instead provides financial rewards intended to incent procurement of DER grid services in the near-term consistent with the Companies' previous plans, subject to a maximum, capped amount, provided below.[182]

- Upside incentive: the Companies will receive a one-time financial award upon acquisition of capacity for certain grid services. The amount of incentive will vary depending on the grid service(s) acquired and the service territory it will serve as follows:

[182]The Commission determined these values using the most current value-of-service ("VOS") analyses filed in Docket Nos. 2017-0352, 2007-0341, 2020-0132, 2020-0136, and 2020-0127 and a reasonable percentage to share value between shareholders and customers. The underlying VOS estimates are filed under confidential seal. The Commission anticipates that these will be updated further prior to future review of competitive solicitations and program offerings.

- Hawaiian Electric FFR1 & FFR2: $13.30 per kW
- Hawaiian Electric Load Build: $6.30 per kW
- Hawaiian Electric Load Reduction: $6.40 per kW
- MECO FFR1: $39.40 per kW
- MECO Load Build: $18.00 per kW
- MECO Load Reduction: $17.70 per kW
- HELCO FFR1: $37.10 per kW
- HELCO Load Build: $18.00 per kW
- HELCO Load Reduction: $17.70 per kW
- The maximum financial reward the Companies may receive for this PIM over the two-year duration of this PIM, on a consolidated basis, is $1.5 million. The maximum share of the financial incentive that may be awarded for grid services on the Oahu system is $1 million.

In developing this PIM, the Commission refers back to the Phase 1 D&O, where it noted:

> . . . [T]he Hawaiian Electric Companies have experienced an unprecedented level of DER adoption in recent years, offering an increasing number of evolving and sophisticated DER program options, ... As observed by staff, "there is an emergent and increasing need to ensure that these resources play an integral role in the function and balancing of the network." The [C]ommission agrees. As the suite of DER options becomes more robust and complex, it is critical that utilities manage these new resources in an efficient manner, such that these resources are

> maximized while also promoting safe, reliable, electrical service.[183]

The importance of integrating DERs into the Companies' system has not diminished since then, and has taken on a greater prominence as more sophisticated and long-term programs are actively being explored in other Commission proceedings.[184] As DERs increasingly become a reality of the electrical grid, it is imperative that their role in the Companies' system correspondingly grows.

While progress has been made in developing iterative programs intended to facilitate renewable generation from DERs, similar projects to harness grid services from DERs has lagged behind. For example, development of programs to improve access and use of customer-sited DERs, while ongoing in Docket No. 2019-0323, has been required to adjust its schedule.[185] While the Commission maintains the urgency in progressing with these related proceedings, it believes that implementing the Grid Services PIM will supplement the efforts currently underway and assist in sustaining the momentum to improve integration of

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[183]Phase 1 D&O at 48.

[184]See Docket No. 2019-0323.

[185]See Docket No. 2019-0323, Order No. 37431, "Approving the Parties' Request to Amend the Procedural Schedule," filed November 5, 2020.

DERs onto the Companies' system and emphasize the critical role the Commission expects DERs to play in efficient grid operations going forward. In this regard, the scheduled retirement of the AES power plant in 2022,[186] as well as the Companies' proposal to delay interconnecting several renewable energy and storage projects recently approved by the Commission,[187] underscores the need for expeditiously securing alternative sources of grid services to ensure that system needs are met. This situation highlights the present opportunity to leverage existing and future DER capacity to meet these needs.

Currently, the Companies' DER grid service programmatic offerings are limited to the Residential and Commercial Direct Load Control programs ("RDLC" and "CDLC," respectively) and the Fast Demand Response Program ("Fast DR"). The Companies report generic customer level impacts of 13.8 MW for the RDLC, 11.7 MW for the CDLC, and 11.9 MW for Fast DR.[188] Unfortunately, the actual

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[186]See In re Public Util. Comm'n, Docket No. 2014-0183, "Hawaiian Electric Companies' PSIPs Update Report," Book 3, filed December 23, 2016, at M-34.

[187]See Docket Nos. 2017-0352 (competitive bidding docket), and 2018-0430, 2018-0431, 2018-0432, 2018-0434, 2018-0435, and 2018-0436 (dockets regarding recently approved projects for which the Companies' are proposing interconnection delays).

[188]See In re Public Util. Comm'n, Docket No. 2007-0341, Letter From: K. Katsura To Commission Re: Docket No. 2007-0341 - Review of Demand-Side Management Reports and Requests for Program

MWs of grid services provided by the RDLC, CDLC, and Fast DR programs is unknown, as the Companies do not have a methodology to measure and record this data.[189] Although the Companies have entered into agreements with third-party aggregators that are anticipated to yield greater amounts of grid service capacity from DERs in the near future,[190] the Commission believes that the situation can be improved by further incenting the Companies to accelerate their efforts.[191]

Further, as indicated in the Companies' October 8, 2020 "Grid Services Procurement Update," the Companies' recent solicitation for grid services has resulted in substantially less amounts of grid services than solicited.[192] Moreover, there appears

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Modifications - Hawaiian Electric Company, Inc. Modification and Evaluation Report, filed November 25, 2020.

[189]See Hawaiian Electric response to PUC-HECO-IR-19(a) and (b), filed August 11, 2020.

[190]See Hawaiian Electric response to PUC-HECO-IR-19(d), filed August 11, 2020.

[191]For example, the Commission notes that under the Companies' agreements with third-party aggregators, if less than expected capacity is delivered the aggregators may be subject to a contractual penalty, but this will not directly address the shortfall in delivered DER grid services. See Hawaiian Electric response to PUC-HECO-IR-19(e).

[192]See Letter From: D. Matsuura To: Commission Re: Docket No. 2018-0088 – Instituting a Proceeding to Investigate Performance-Based Regulation; Hawaiian Electric Companies' 2021 Grid Services Procurement Update, filed October 8, 2020 ("Grid Services Procurement Update"), Attachment 1 at 1.

to be uncertainty as to how the Companies intend to address this shortfall, as the Grid Services Procurement Update substitutes previous statements representing another round of procurement for a need to "perform an update of the grid services needs given the significant changes in underlying resource assumptions."[193] As such, the annual award for this PIM has been calibrated with the intention of incenting the Companies to procure grid services from DERs to meet to their prior, unfulfilled, targets.[194]

Accordingly, the Commission believes the inclusion of the Grid Services PIM will help address this situation by incenting the Companies to more aggressively integrate DER grid services. This will become increasingly important as the Companies begin to retire their aging fossil fuel plants, creating an opportunity for renewable resources to step in to fill this role. To the extent the Companies can maximize the use of DERs for grid services, this will help to reduce, defer, or entirely avoid costs associated with acquiring and operating alternative, more costly, resources.

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[193]Grid Services Procurement Update, Attachment 1 at 1.

[194]The Commission observes that in, "Hawaiian Electric's revised December 18, 2020 Status Conference Presentation," which was filed in Docket No. 2017-0352, slide 10 indicates a commitment to issue a Grid Services RFP in Q1 2021.

The Commission appreciates the considerations raised by the Parties in response to this PIM proposal,[195] and affirms that this PIM is intended to be interim in nature, ending after 2022. During this interim period, the Commission will continue its examination of this PIM in the context of the DER proceeding (Docket No. 2019-0323) to determine how this PIM can be refined to specifically incent utilization of grid services from DERs, including a symmetric design of rewards and penalties, with the intent of replacing the Grid Service PIM with a more sophisticated version in 2023. This will involve the Companies developing a methodology to measure and report how they are currently utilizing enrolled DERs to provide grid services,[196] and to facilitate this ongoing examination, the Commission will include this as a Reported Metric or Scorecard to be developed in the Post-D&O Working Group, as discussed, infra.

Relatedly, the Commission finds that these efforts should be complemented with a comprehensive analysis assessing the

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[195]See Hawaiian Electric response to PUC-Parties-IR-15; COH response to PUC-Parties-IR-15; C&CH response to PUC-Parties-IR-15; Ulupono response to PUC-Parties-IR-15; Blue Planet and DER Parties joint response to PUC-Parties-IR-15; and Consumer Advocate response to PUC-Parties-IR-15, all filed on November 18, 2020.

[196]See Hawaiian Electric response to PUC-HECO-IR-19(b) (indicating that the Companies currently do not have a methodology for accurately verifying the amount of enrolled DER that are participating and delivering grid services.).

grid services needs of Hawaiian Electric's systems.[197] As the Companies proceed with retiring their existing fleet of fossil fuel plants, it is imperative that grid services fulfilled by those facilities continue to be provided, and that the system is prepared to accommodate the new challenges expected with Hawaii's energy transformation. Thoughtful and timely planning will play an important role in this transition by identifying grid service needs and alternative solutions. Accordingly, the Commission intends to pursue this issue in the DER docket (Docket No. 2019-0323) and/or the Integrated Grid Planning docket (Docket No. 2018-0165), as appropriate.

iii.

RPS-A PIM

This PIM was proposed by Ulupono and is intended to incent the Companies to accelerate their progress toward achieving

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[197] C.f., Grid Services Procurement Update, Attachment 1 at 1 ("However, upon further deliberation, including reassessment of the current underlying facts and circumstances, the Companies' position is that a specific DER grid services procurement is prudent after the Companies perform an update of the grid services needs given the significant changes in underlying resource assumptions.").

the State's Renewable Portfolio Standards ("RPS")[198] ahead of the statutorily prescribed schedule ("RPS-A PIM").[199]

Ulupono maintains that the RPS-A PIM is expected to promote progress towards a number of PBR Outcomes, including:

- *DER Asset Effectiveness*: DERs may be advantaged as they can be added to the system more quickly than competitive procurements.

- *Customer Engagement*: With a reward available every year, the utility will have an incentive to offer attractive programs to bring more customer-sited renewables on the system.

- *Interconnection Experience*: The reward will only be available after the renewable resource is interconnected, providing a strong incentive to expedite the interconnection experience for both utility-scale and customer-sited DER projects.

- *Cost Control*: The utility has no control over oil prices, but will have some control regarding how quickly they can add competitively priced renewables onto the system.

- *Affordability*: Renewables are now cost-competitive with oil and are generally contracted at fixed-price PPAs, providing customers with more affordable, less volatile rates over longer periods of time.

- *Grid Investment Efficiency*: With a strong incentive to accelerate the RPS [(complemented by cost containment incentives introduced by the structure of the MRP and ARA)], the utility will have the incentive to invest as efficiently as possible to ensure the system can support increased amounts of renewables under a more accelerated timeframe.

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[198]See HRS § 269-91, et seq.

[199]See Ulupono ISOP at 64-67.

- *GHG Reduction*: Most renewable generation has zero GHG emissions at the source of generation.[200]

In addition to promoting the above PBR Outcomes established in this proceeding, Ulupono submits that the RPS-A PIM benefits from being relatively simple to administer, as the rewards and penalties are determined by objective statutorily defined standards which have been in place and with which the Commission and Companies have experience measuring and reporting.[201]

The structure of the RPS-A PIM is as follows:

- Metric: the metric will be the Companies' annual compliance with the RPS (% and year-based milestone),[202] on a consolidated basis. The PIM will utilize a "corrected" methodology, where the RPS will calculated based on the total system renewable generation divided by total system generation of electricity, rather than division by net sales.

- Target: the target will be the RPS goals for 2020, 2030, and 2045, as established by statute, interpolated between milestone dates. If the Companies' corrected RPS percentage is above the interpolated statutory goal, they are eligible for a reward. Specifically, during interim periods between statutory milestone dates, if the Companies' corrected RPS percentage is above a straight-line interpolation of the increase during the interim years, the Companies are eligible for a reward.

- Upside incentive: the Companies may earn a reward in $/MWh, calculated on a target revenue basis,

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[200]Ulupono ISOP at 64-65 and Exhibit B-2; see also, Ulupono RSOP at 93-94 and Exhibit B-2.

[201]See Ulupono RSOP at 98-99.

[202]See HRS § 269-92.

for the amount of system generation above and beyond the corrected, interpolated statutory RPS goal. The Companies may earn this reward on an annual basis. The Commission has increased the potential reward in the early years of the MRP to encourage further acceleration of renewable development associated with the upcoming retirements of fossil-fueled plants and support post-COVID economic recovery. The annual schedule will be $20/MWh in 2021 and 2022, $15/MWh in 2023, and $10/MWh for remainder of the MRP. Rewards will be allocated among the Companies on a 70/15/15 basis, similar to the Interconnection Approval PIM.

- Downside incentive: penalties are as already prescribed in the RPS ($20/MWh for failing to meet an RPS target).[203] As this PIM incorporates the statutory penalty, penalties may only be assessed against the Companies on statutory milestone years (i.e., 2030, 2040, and 2045).

According to Ulupono, the RPS-A PIM "is an outcome-based PIM, broadly supported under existing statutory law and practical implementation experience, that has the potential to achieve fruitful alignment of utility incentives and Hawaii's energy policy mandates and objectives."[204] As Ulupono states:

> Specifically, the RPS-A PIM should foster selection and implementation of the lowest (net present value) price energy solutions capable of achieving the 100% RPS requirement because most renewable energy additions will be competitively procured which helps keep prices down. The RPS-A PIM should also provide incentives that result in the selection of

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[203]See In re Public Util. Comm'n, Docket No. 2007-0008, Decision and Order No. 23912, filed December 20, 2007, and Decision and "Order Relating to RPS Penalties," filed December 19, 2008.

[204]Ulupono ISOP at 61.

> energy solutions that are agnostic as to utility or non-utility ownership, as utility self-build and affiliate proposals may also be considered. In short, the RPS-A PIM should also be able to fully align the utility on increased DER adoption and fast interconnection times through one relatively simple and powerful measure.[205]

The Companies, while voicing support for the RPS-A PIM, have suggested some slight modifications. In particular, the Companies have suggested that the "corrected" RPS standard not be implemented until 2025, to account for plans already in place for the Companies based on existing RPS standards.[206] According to the Companies, "[t]he plans that the Companies developed and have been executing over the last several years were based on the RPS calculation currently in place[,]" and "[t]o hold the Companies to a higher standard each year through 2025, a period for which the Company has very little ability to change its plans or increase renewables materially beyond its current plans . . . would effectively amount to moving the goal posts late in the game."[207]

Of the Parties, the Consumer Advocate has voiced the strongest concerns with the RPS-A PIM, including Ulupono's

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[205]Ulupono ISOP at 93.

[206]Hawaiian Electric response to PUC-HECO-IR-46(b), filed September 17, 2020. See also, Hawaiian Electric RSOP at 256.

[207]Hawaiian Electric RSOP at 256.

benefit-cost analysis, which relies on a monetized cost of carbon, and the overlapping nature of the RPS-A PIM with other proposed Performance Mechanisms.[208] The Consumer Advocate clarifies that it supports accelerating the integration of renewable energy onto the Companies' system, but only "when such acceleration can results [sic] in benefits for all customers."[209]

After considering the arguments made by Ulupono and the other Parties, and carefully reviewing the record, the Commission finds the RPS-A PIM to be reasonable and will approve it, as proposed by Ulupono and as modified herein, including immediate application of the "corrected" RPS methodology.

In so doing, the Commission has taken the following considerations into account:

- The RPS-A PIM has been extensively discussed, reviewed, and vetted by the Parties during the Working Group process, with many of the Parties continuing to offer their support;[210]

- The metric is quantifiable and calculated pursuant to an open and transparent methodology;

[208]See Consumer Advocate RSOP at 163-64.

[209]Consumer Advocate RSOP at 164.

[210]See Hawaiian Electric response to PUC-HECO-IR-46; Blue Planet response to PUC-Parties-IR-13, filed September 17, 2020; Blue Planet Post-Hearing Brief at 18; COH response to PUC-Parties-IR-13, filed September 16, 2020; and LOL response to PUC-Parties-IR-13, filed September 17, 2020.

- Ulupono has performed an extensive benefit-cost analysis in support of the RPS-A;[211]

- The RPS-A PIM incorporates the existing RPS penalty structure and complements it with a reward structure for exemplary performance in exceeding statutory goals and

- The current "pipeline" of renewable energy projects that have been approved, but are still under development, provides the Companies with opportunities to earn rewards under this PIM and incentivizes them to bring them on-line as quickly as possible.

In response to the Companies' position that the "corrected" RPS methodology should be delayed until 2025, the Commission underscores that the RPS-A is a PIM intended to reward <u>exemplary</u> performance, and is not something that should be adjusted to account for the Companies' current performance or otherwise be calibrated to make attainment easier. Given that the "corrected" methodology is fundamental to more accurately measuring the desired performance, the Commission is not persuaded that delaying its application until 2025 is reasonable or desirable under the circumstances.

While the Commission understands the Consumer Advocate's concerns with using ratepayer funds to incent otherwise non-monetized societal objectives (i.e., reduction in carbon emissions),[212] the Commission is not persuaded at this time that

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[211]<u>See</u> Ulupono ISOP at 71-75; and Ulupono RSOP at 102-05.

[212]<u>See</u> Consumer Advocate RSOP at 163.

this is sufficient to reject the RPS-A PIM. As has been demonstrated in this proceeding, developing Performance Mechanisms, particularly PIMs and SSMs, is complex, can be contentious, and embodies a degree of uncertainty that cannot be resolved until the PIM or SSM is actually deployed. While the considerations raised by the Consumer Advocate are not inconsequential, in order to move forward with transitioning to a PBR Framework, a certain level of uncertainty will likely be present, and the Framework approved in this D&O reflects significant balance and compromise among the various positions voiced by the Parties. In the event that the RPS-A PIM does not function as intended, or otherwise leads to undesirable consequences, the network of safeguard mechanisms built into the PBR Framework will allow the Commission to address this in a timely manner.

Similarly, while the RPS-A PIM may potentially overlap with other Performance Mechanisms,[213] the Commission, upon considering the circumstances, including the multiple PBR Outcomes addressed by the RPS-A PIM and the novelty of the PBR Framework in

[213]For example, the RPS-A PIM may overlap with aspects of the Interconnection Approval PIM and existing SSMs related to the Companies' competitive procurement of grid-scale renewable energy approved in Docket No. 2017-0352. C.f. Consumer Advocate RSOP at 163-64 (voicing concerns that "the RPS-A is duplicative of other proposed PIMs and SSMs[.]").

general, does not believe this factor, alone, is dispositive. Ulupono defends this aspect of the RPS-A PIM, noting that while common projects may be eligible for other performance awards, in addition to the RPS-A PIM, this does not necessarily mean they are duplicative – for example, Ulupono submits that the existing SSM related to the Companies' efforts to competitively procure grid-scale renewable energy is distinct from the RPS-A PIM, contending that the RPS-A PIM would incent the speed and volume at which renewable energy is integrated onto the Companies' systems, whereas the SSM incents procurement of renewable energy at reasonable and cost-effective prices.[214]

In sum, upon careful review of the record and weighing the considerations raised by the Parties, the Commission finds the RPS-A PIM, as described above, to be reasonable and consistent with the PIM-specific design considerations identified in the Phase 1 D&O. Further, as noted in Section IV.E.3, infra, the Commission will be reviewing all of the PIMs as part of the annual review cycle, and there are a number of safeguard mechanisms that allow the Commission to review and modify any of these

[214]Ulupono RSOP at 134-35; see also, Ulupono response to PUC-Ulupono-IR-12, filed September 16, 2020; Blue Planet response to PUC-Parties-IR-13(d) and (e); Hawaiian Electric response to PUC-Parties-IR-13(d) and (f), filed September 17, 2020; and Hawaiian Electric response to PUC-HECO-IR-37(f), filed September 17, 2020.

PBR mechanisms as appropriate, in the event they are not operating as intended.

iv.

Low-to-Moderate Income Energy Efficiency PIM

This PIM is intended to promote the PBR Outcome of *Customer Engagement*, as well as *Customer Equity* and *Affordability*, by incenting the Companies to collaborate with Hawaii Energy[215] to deliver energy savings for LMI customers ("LMI Energy Efficiency PIM"). This PIM is not intended to incent the Companies to offer its own energy efficiency programs or to compete with Hawaii Energy; rather, the PIM is intended to incent the Companies to promote Hawaii Energy programming and to optimize load and customer interactions via tools within their jurisdiction such as rate design and the provision of energy usage data. It will feature only an "upside" incentive and incorporate two metrics that will reward the Companies for: (1) delivering energy savings for eligible customers beyond an established baseline; and (2) increasing participation rates of eligible customers in Hawaii Energy programs. As described herein, the Commission instructs

[215]Hawaii Energy is the ratepayer-funded conservation, efficiency, and demand-side management program operated by the Public Benefits Fee Administrator under contract with the Commission.

the Post-D&O Working Group to complete refinements to this PIM, but outlines the basic structure of the PIM below:

- Metric:
    - The first metric will reward realized energy savings or load reductions for customers identified by Hawaii Energy as LMI. The Post D&O Working Group should recommend an appropriate way to measure achievement of this objective (e.g. savings as a percentage of sales, normalized load compared to an established baseline, etc.).
    - The second metric will reward increased participation in selected Hawaii Energy programs facilitated by the Companies' efforts (e.g. percent change in LMI customers participating in Hawaii Energy LMI programs year-to-year, etc.).
- Targets: Targets and any relevant initial or incremental thresholds for both metrics will be recommended by the Post-D&O Working Group to incent performance beyond a determined baseline.
- Upside incentive: Rewards for both metrics should be collectively capped at $2,000,000, calculated on a target revenue basis.
- This PIM will initially have a duration of three years but will be subject to an annual review.

In deciding to proceed with this PIM, the Commission has taken into account a number of considerations. As the Phase 1 D&O recognized:

> "[u]tilities need to adequately and equitably facilitate a move toward an inclusive, customer-oriented electric grid, as customers evolve from passive consumers of a commodity (kWh) to active participants in a dynamic market for grid services." [footnote omitted] This not only involves tracking customer participation in the Companies' new program

> offerings, such as DER, CBRE, and Demand Response, but also developing effective outreach tools to educate customers about their electricity consumption and how they can better manage it, whether it be through energy-saving practices, or taking on more active role as market participant or as an energy and grid services provider.[216]

The LMI Energy Efficiency PIM facilitates these objectives in multiple ways, and the Commission believes that the benefits of such a PIM outweigh the associated costs.

In particular, this PIM will require the Companies to engage with customers to market their own and Hawaii Energy's programs and to help customers understand and manage their energy usage. Hawaii Energy's mission "is to empower island families and business to make smarter choices to reduce energy consumption, save money, and pursue a 100% clean energy future".[217] As evidenced by Hawaii Energy's achievements in outreach, partnerships, and relationship building, energy efficiency and demand-side management are proven tools for customer engagement that provide customers with options and choices for managing their consumption and bills. Increased collaboration between Hawaii Energy and the Companies will be mutually beneficial for both organizations and

[216]Phase 1 D&O at 47 (citing Phase 1 Staff Report #3 at 26).

[217]See Hawaii Energy Annual Report 2019-2020 at 2, available at https://hawaiienergy.com/about/information-reports, last accessed December 5, 2020.

will help to maximize the effectiveness of every customer interaction through mutual promotion of programs, consistent marketing, and increased data and information sharing.

Additionally, this PIM incents actions that facilitate equitable customer participation in the energy transition. The COH correctly points out that, "Hawaii's residential electricity rates are consistently highest in the country and constitute a significant financial burden for [LMI] ratepayers on all islands".[218] The COH also explains:

> Households making up to 100% of the Federal Poverty Level ("FPL") devote 14% of their gross income to energy costs, which are overwhelmingly driven by electricity bills. By contrast, wealthier residents across the state only devote about 2% of their pre-tax income to energy costs.[219]

The COVID-19 emergency has only exacerbated challenges for Hawaii residents, creating an economic recession and changing energy consumption patterns as residents spend more time at home. The corresponding increased electricity charges associated with increased consumption particularly affect LMI residents, who have fewer resources and limited opportunities to offset their energy bills. Pertinently, the Commission observes that the other PIMs

[218]COH ISOP at 1.

[219]COH ISOP at 6 (footnotes and citations omitted).

included in the PBR Framework place a necessary emphasis on other DERs, but that these resources may not be accessible for all residents, underscoring the need for a PIM such as the LMI Energy Efficiency PIM.

In response to PUC-Parties-IR-11, PUC-Parties-IR-12, and PUC-Parties-IR-14, Parties expressed support for the overall concept and objectives of this PIM. Generally, concerns raised by Parties were relevant to the particular details of the proposed mechanisms. For example, the Consumer Advocate notes that:

- Well-designed energy efficiency programs serving LMI customers are essential in promoting customer equity and allowing this important customer group to benefit from emerging clean energy technologies and practices.

- Well-designed financial incentives can be an effective tool to encourage the utilities to promote and expand efficiency savings for LMI customers.

- Financial incentives to utilities should ideally be justified on evidence indicating that the costs of the incentives are worth the benefits. This principle is challenging in the context of LMI efficiency savings, where one of the key benefits, reduced energy burden, is difficult to quantify and monetize. . . ."[220]

[220]Consumer Advocate response to PUC-Parties-IR-14, filed November 13, 2020.

The Commission concurs that the benefits to LMI customers can be difficult to quantify and emphasizes that energy efficiency and demand-side management are low-cost resources that are generally cost-effective. Blue Planet Foundation and the DER Parties express similar support, stating:

> . . . Hawaiʻi Energy's evaluation reports have consistently shown that energy efficiency is highly cost-effective at the current stages of the adoption curve. This should be even more the case for LMI customers who have been generally underserved by energy efficiency programs relative to the broader customer population. In any event, to the extent that achieving energy savings for harder-to-reach customers like the LMI segment may require additional costs, such a potential cost premium (or even a subsidy, if necessary) should *not* deter the adoption of incentives to promote much-needed LMI customer access to clean energy benefits.[221]

Energy efficiency and demand-side management are also critical utility system resources that provide load shaping and shifting to help align supply and demand in a cost-effective manner. In particular, thoughtful rate design can help to align savings under this PIM with savings that will maximize system benefits. Optimizing load first can also reduce the costs necessary to achieve the RPS and the RPS-A PIM, providing an additional cost control measure.

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[221]Blue Planet and the DER Parties Joint response to PUC-Parties-IR-14(b)(emphasis in the original).

For these reasons, the Commission reiterates its intention that a customer-centric and equitable PBR Framework is of upmost importance and adopts the LMI Energy Efficiency PIM.

That being said, the Commission recognizes that this PIM was introduced in the latter stages of this proceeding and that further development is desirable. Accordingly, the Post-D&O Working Group established as part of this D&O is directed to develop recommended baselines, thresholds for awards, and further refinements to both metrics for this PIM. In so doing, the Post-D&O Working Group should consider a PIM design, threshold target, and reward increments that will provide flexibility in earnings opportunities and that recognize the unique challenges of Hawaii's energy landscape.

Regarding the first metric, eligible customers should include residential premises in all zip codes designated by Hawaii Energy as eligible for their Affordability and Accessibility programs across all the Companies' service territories. The eligible LMI customer segment will be defined in alignment with Hawaii Energy's zip code methodology, including any one-off households not within the eligible zip codes included by Hawaii Energy in their LMI programs.

The Commission also recognizes that the COVID-19 pandemic has financially impacted residents who may not be captured within this definition. The Post-D&O Working Group should explore ways to include residents who have been adversely impacted by the pandemic and/or that may be newly included in the LMI customer segment as eligible for this PIM. For example, the Companies may provide information to Hawaii Energy on customers in arrears or that are participating in payment assistance programs to allow Hawaii Energy to target programs to those who can benefit from them.

The Commission acknowledges Party concerns raised in response to PUC-Parties-IR-14 that the zip code methodology may not capture all LMI customers and/or may include non-LMI customers (free-riders). In response, the Commission has modified this PIM, as initially presented in PUC-Parties-IR-14, to enable all LMI households identified as eligible by Hawaii Energy to be included as well. While this may add some administrative burden, this will help to ensure that all LMI customers are eligible for this programming. In developing recommended refinements for this PIM, the Post-D&O Working Group should bear this overarching goal of inclusion in mind.

Additionally, the Commission observes that energy efficiency is an overall cost-effective resource that puts downward pressure on rates for all customers. Therefore, benefits from programming incentivized under this PIM delivered to non-LMI customers are still important and will contribute to this effect. The COH, Blue Planet, and the DER Parties support this methodology as a good starting place that will avoid overly burdensome verification processes.[222] The Commission encourages collaboration amongst Hawaii Energy, the Companies, and other Parties, to develop more precise methodologies to determine eligibility for LMI programs using census data in future years.

In addition, the Commission has considered the thoughtful perspectives shared by the Parties regarding first-year versus lifetime savings in their responses to PUC-Parties-IR-14. The Commission agrees that forward-looking lifetime savings are an important measure that capture the benefits of sustained energy saving over time.[223] However, while creativity in meeting this PIM is encouraged, the Commission also recognizes that prominent tools at the Companies' disposal for delivering energy savings for LMI customers, such as rate design and behavioral feedback, typically have shorter measure lives. As a result, the Commission directs the Post-D&O Working Group to focus initially on first-year savings as the metric, as this provides simpler and clearer methods for

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[222]See COH response to PUC-Parties-IR-14(f); and Blue Planet and the DER Parties Joint response to PUC-Parties-IR-14(f), both filed November 13, 2020.

[223]See Blue Planet and the DER Parties Joint response to PUC-Parties-IR-14(a).

reporting and verifying achievement of the PIM, as noted by several of the Parties.

In setting the second metric based on increasing participation rates for eligible customers in Hawaii Energy programs, this PIM should focus on the number or percentage of LMI customers that participate and that drive energy savings results. The programs selected for inclusion in this PIM should have reasonably similar participation levels. For example, the PIM should not include programs that target just a few large participants alongside programs that reach hundreds of individual participants. The Post-D&O Working Group is encouraged to use existing Hawaii Energy reporting on program participation to establish a relevant baseline for this metric.

The Commission observes that the Companies can also help drive increased participation in Hawaii Energy programs through data sharing efforts that will allow effective outreach to eligible customers. Therefore, the Commission strongly encourages data sharing between the Companies and Hawaii Energy that will support program expansion to LMI customers.

This PIM is intended to incent the Companies to maximize the effectiveness and reach of every customer interaction through promotion of its own and Hawaii Energy's programming. As with the first metric, the Commission does not envision this PIM focusing on utility inputs, but should incent actual system and customer impacts. The Post-D&O Working Group should focus on a reward structure that measures increased participation in select Hawaii Energy programs for eligible customers, rather than marketing efforts or customer intentions to participate.

The Commission recognizes that some Parties expressed concern regarding savings attribution between Hawaii Energy and the Companies.[224] However, the Commission agrees with Blue Planet and the DER Parties that "[o]utcome-based PIMs purposefully seek to encourage broader energy sector and market transformation and innovation[,]"[225] and emphasizes the intent of this PIM to foster collaboration rather than competition.

The Commission also observes that concerns over attribution are mitigated by establishing an outcome-based reward structure that measures energy savings regardless of how they were achieved, especially given the second metric which explicitly incents the Companies to drive increased participation in Hawaii Energy programs. Therefore, the Commission directs the Post-D&O Working Group to develop metrics, targets, and thresholds

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[224]See Ulupono response to PUC-Parties-IR-14(e), filed November 13, 2020.

[225]Blue Planet and the DER Parties Joint response to PUC-Parties-IR-14(e).

aligned with this disposition. Additionally, the established reporting requirements below will allow the Commission to confirm that the Companies have indeed put forth efforts to achieve this PIM and to collaborate effectively with Hawaii Energy without duplicating efforts.

The Post-D&O Working Group is encouraged to use research on energy efficiency, rate design, and energy usage feedback programs that provide information on achievable savings, including research specifically targeting impacts on LMI customers specifically in Hawaii, to inform the PIM targets. Using data provided by the Companies in response to PUC-HECO-IR-51 and Hawaii Energy Evaluation, Measurement, and Verification ("EM&V") reports, the Commission observes that Hawaii Energy has consistently achieved around 0.22% of savings as a percentage of sales in the residential hard-to-reach sector.[226] The Post-D&O Working Group may consider setting the threshold incentive level

[226]From 2017-2019, Hawaii Energy achieved between 0.21% and 0.23% savings as a percentage of sales. Achievements were similar, but fluctuated more in 2015 (0.28%) and 2016 (0.16%). These achievements were calculated as first-year net energy savings from residential hard-to-reach or economically disadvantaged programs as a percentage of unadjusted total sales (PV and non-PV customers) reported by the Companies in response to PUC-HECO-IR-51. Hawaii Energy EM&V reports can be found at: https://hawaiienergy.com/about/information-reports.

above this, which would incent actions by the Companies to increase savings above current achievement by Hawaii Energy.

Further, the Commission encourages the Post-D&O Working Group to consider that the Companies currently have a multitude of options to engage customers to reduce consumption at the targeted levels that complement Hawaii Energy programming, and that also leverage existing and currently planned investments, such as AMI. For example, efforts may include time-of-use rates and energy usage feedback.

The Commission reiterates that a major intention of this PIM is to incent collaboration between the Companies and Hawaii Energy. For this reason, the Commission establishes threshold reporting requirements the Companies will be required to submit in order to earn the incentive in addition to reporting on established metrics. These reporting requirements include:

- Descriptions of efforts taken by the Companies towards achieving this PIM, including:
    - Identifying relevant programs offered directly by the Companies to targeted customers;
    - Efforts taken by the Companies to promote Hawaii Energy programming to targeted customers;
    - The cost of the Companies' relevant efforts, such as marketing for advanced rates, energy usage data provision efforts, and promotion of energy saving programs;

    - The number of eligible customers reached with relevant marketing and promotional materials, advanced rates, and data provision efforts;

- Descriptions of data sharing efforts between the Companies and Hawaii Energy, including data provided by both entities and data requested by each entity that was not provided, including an explanation of why the data was not provided;

- Annual first year energy savings for eligible customers over baseline values, as determined by the Post D&O Working Group, aggregated by zip code and island; and

- Participation in selected programs in absolute terms and as a percentage of the eligible population compared to baseline values, as determined by the Post-D&O Working Group, aggregated by zip code and island.

The Commission recognizes that this PIM is a novel effort that will require ongoing evaluation and may require adjustments as the Companies gain experience with it. These reporting requirements may also help to refine the PIM design in future years. Additionally, there are outstanding questions as to the details of implementing this PIM in year one of the MRP.

Consequently, the Commission directs the Post-D&O Working Group to collaborate with Hawaii Energy and the Public Benefits Fee Technical Advisory Group to address the following items and questions prior to the PIM's implementation:

- What metrics, targets, and incentive increments should be established for both metrics of this PIM that will be achievable and that will reasonably incent action by the Companies?

- Are the reporting requirements above reasonable and effective for measuring PIM achievement and for collecting data necessary to evaluate the PIM's effectiveness?

- Does the PIM need to be adjusted in terms of customer eligibility and/or baselines and thresholds on a temporary basis to account for the effects of the COVID-19 pandemic?

- What verification and reporting methods should be established for this PIM that do not place undue burden on Hawaii Energy or duplicate EM&V efforts?

- Should the PIM align with the calendar year or with Hawaii Energy's program year?

- Should the targets and rewards be consolidated or split across the three Companies?

v.

AMI Utilization PIM

This PIM is intended to promote the PBR Outcomes of *Customer Engagement* and *DER Asset Effectiveness*, as well as *Grid Investment Efficiency*, by incenting the Companies to accelerate utilization of AMI interval data ("AMI Utilization PIM").

As the Companies continue to invest in modernizing their grid to meet evolving needs, it is critical they maximize both system and customer benefits from these significant investments. The deployment of AMI across the Companies' service territories provides a new opportunity to use granular energy consumption data to send more accurate and dynamic price signals, enable better customer understanding of energy usage, and improve program design and grid operations.

Given these potential use cases, the PBR Framework will include a PIM that incents the Companies to accelerate the number of customers with advanced meters enabled to support time-varying rates and next generation DER programs to set a foundation for future utility applications.

This PIM builds off an SSM approach proposed by the Consumer Advocate throughout Phase 2 and articulated in their ISOP:

> Advanced metering infrastructure (AMI) can reduce operational costs and provide the vehicle for expanded grid services and programs. The Companies are able to reduce operational costs such as meter reading and connections or disconnections. They enjoy more successful revenue collection through the availability to offer pre-pay billing or reduce meter tampering and increase theft detection. These operational costs savings and revenue collection enhancement benefits will be enjoyed by the Companies and retained for shareholders under the structure of the MRP, unless MPIR/MPSR accounting captures these offsetting costs savings as reductions in revenue increase under those mechanisms. The Companies may also use AMI for developing new programs, service offerings, and other features such as voltage monitoring in support of grid control. These types of benefits could yield benefits captured as MPIR/MPSR offsets, system benefits offsetting fuel costs or benefits retained by shareholders under the MRP. To the extent the Companies achieve savings or produce new benefits through deployment of AMI that are enjoyed only by

> customers (e.g. reduced energy costs), the Consumer Advocate believes that evaluation of a shared savings mechanism (or mechanisms for different programs) may be warranted to encourage the Companies to develop such programs to deliver benefits to customers even if the Companies would not directly benefit through the ARA.[227]

The Commission further explored the Consumer Advocate's proposal in PUC-CA-IR-15, to which the Consumer Advocate provided further details from a recent American Council for an Energy-Efficient Economy report ("ACEEE AMI Report") which found:

> " . . . many utilities are underexploiting AMI capabilities and its attendant benefits, thus missing out on a key tool to deliver value to their customers and systems. In particular, they underutilize AMI's ability to support customer energy efficiency through information, pricing, and technical assistance insights, and its ability to improve program design through targeting, [pay for performance (P4P)], and more robust evaluation. When they neglect to use AMI data, they also largely undervalue the potential grid benefits from efficiency programs in grid-interactive efficient buildings.[228]

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[227]Consumer Advocate ISOP at 114-15.

[228]Consumer Advocate response to PUC-CA-IR-15(a), filed November 13, 2020, at 99 (citing Gold, Rachel, Corri Waters, and Dan York, *Leveraging Advanced Metering Infrastructure To Save Energy* (ACEEE, Report U2001, January 3, 2020, revised January 27, 2020), at 42). Available at https://www.aceee.org/research-report/u2001).

The Consumer Advocate further noted that the ACEEE AMI Report "identified seven different use cases that illustrated how a utility could utilize AMI, directly and indirectly, to benefit customers through enhanced energy savings[:]"[229]

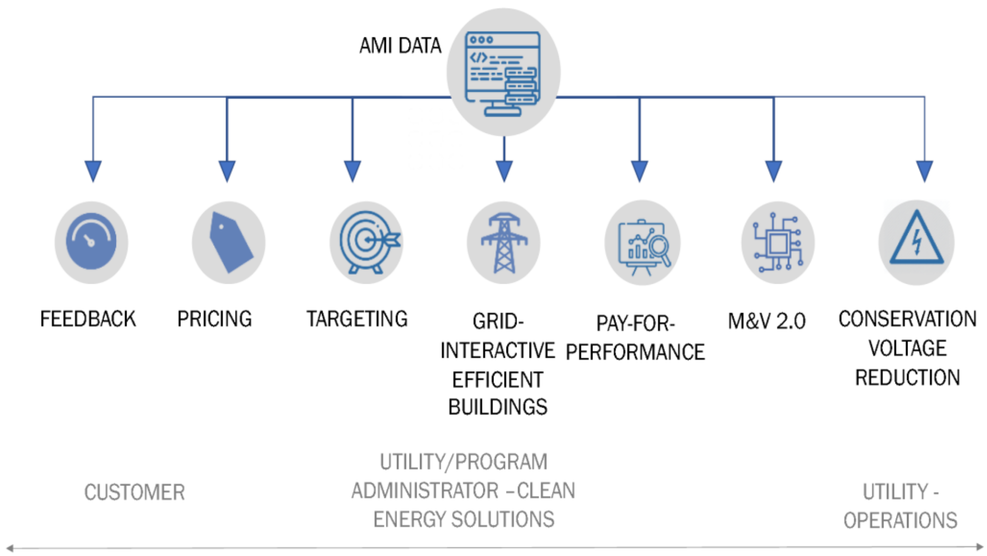

Figure 2. Use cases to leverage AMI for energy savings

The Consumer Advocate suggests that the Companies could implement one or more of these seven different strategies to leverage AMI for the benefit of customers, and that any resulting energy savings could form the basis for an SSM.[230]

The Commission concurs with the Consumer Advocate that AMI has the opportunity to provide benefits under multiple use

[229]Consumer Advocate response to PUC-CA-IR-15(a) at 99-100.

[230]Consumer Advocate response to PUC-CA-15(a) at 100-101.

cases and strategies. To support the successful leveraging of these opportunities, the PBR Framework will include a PIM focused on the number of customers with advanced meters that will enable them to participate in more sophisticated rate structures and DER programs, which is expected to provide a near-term opportunity to accelerate the development of internal processes needed to support these grid investments. As the Companies continue to deploy AMI over the next five years, the Commission expects the Companies to identify ways to expeditiously install advanced meters and improve internal processes to deliver system benefits through the provision of real-time energy usage data and behavioral insights, improved program design and targeting, and more efficient grid operations. The Commission expects this PIM to evolve along with this experience and the new opportunities that emerge.

This PIM will expand on the endeavors initiated by the Companies in Docket No. 2018-0141, in which the Companies are in the process of deploying approximately 68,300 advanced meters on an opt-out basis in targeted areas beginning in 2021, with plans to ultimately install approximately 175,000 meters by 2023.[231]

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[231]See Docket No. 2018-0141, Decision and Order No. 36230, filed March 25, 2019 (approving the Companies' first phase of its Grid Modernization Strategy), which will be implemented between 2019 and 2023); and Docket No. 2018-0141, Hawaiian Electric response to PUC-IR-110, filed November 6, 2020 (confirming deployment of advanced meters).

As described in the Companies' Phase 1 Grid Modernization Strategy, these advanced meters are intended to "record electricity demand, usage and power characteristics in configurable intervals, as well as send notifications for anomalous conditions to provide the Companies with more insight into the distribution grid and support the Companies' growing portfolio of customer energy options."[232] The Companies also are planning to accompany the deployment of advanced meters with the buildout of:

- A meter data management system, which "collects and stores the data received from the advanced meters on both a scheduled and an on-demand basis, enabling customer energy options, data analytics to better refine load profiles for forecasting and grid planning, alerts for system operators regarding anomalous conditions, and a customer portal to empower customers through access to their energy usage data;" and

- An interoperable, scalable telecommunications network, which "enables the communication path for both advanced meters and field devices for distribution sensing, control and automation."[233]

A PIM focused on ensuring that the structures and processes to leverage these grid modernization investments are in

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[232]Docket No. 2018-0141, "Application of Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., Maui Electric Company, Limited for Grid Modernization Strategy Phase 1; Docket No. 2018-0141," filed June 21, 2018 ("Grid Mod Application"), at 3.

[233]Grid Mod Application at 3.

place will provide the Companies with the opportunity to optimize the capabilities of these technologies and platforms in the future, while maximizing benefits to ratepayers. This PIM also will support the discussions on advanced rate design taking place in Docket No. 2019-0323, focusing on developing new DER policies for the Companies. Parties to that proceeding are in the midst of discussing strategies and timelines for implementing time-varying rate designs for both residential and commercial customers.[234]

Considering these complementary efforts and the potential to expand customer savings, the Commission directs the Post-D&O Working Group to focus on finalizing a PIM that accelerates the number of customers with advanced meters enabled to support time-varying rates and next generation DER programs. To help facilitate this discussion, the Commission provides the following guidance:

- Metric: The Commission is inclined to use the percent of each Company's total customers with advanced meters enabled to support time-varying rates and next generation DER programs. The Post-D&O Working Group should consider what internal structures and processes must be in place, beyond simply meter deployment, to enable customers to benefit from AMI investments, and how these improvements can be incorporated into the PIM.

[234]See Docket No. 2019-0323, Order No. 37066, "Establishing Procedural Details and Modifying Hawaiian Electric's Customer Grid Supply Plus Program for Hawaii Island, filed April 9, 2020.

- Targets: Targets should consider the Companies' forecasted advanced meter deployment for their *Phase 1 Grid Modernization Strategy*, as reflected below.

Forecasted Meter Deployment						
	2019	2020	2021	2022	2023	Total
DR	0	0	36,871	11,747	11,876	60,494
Replacement Meters	3,566	20,031	20,031	20,031	20,031	83,690
CGS+	500	8,267	4,133	800	0	13,700
New Meter Sets	1,813	2,645	2,645	2,645	2,645	12,393
Smart Export	179	2,953	1,476	285	0	4,893
Total	6,058	33,896	65,156	35,508	34,552	175,170

  - Since filing these forecasts, the Companies have experienced a number of delays in implementing their Phase 1 strategy. As of September 30, 2020, the Companies had only deployed 4,965 meters.[235] However, the Companies maintain that they will complete installation of approximately 175,000 meters by 2023.[236] Taking these goals into account, targets for this PIM should represent improvement over this current deployment schedule.

  - Targets should be the same across the Companies to ensure customers in all service territories benefit from AMI deployment. After 2023, this PIM could be reassessed to align with the Companies' *Phase 2 Grid Modernization Strategy* and other relevant proceedings.

  - Potential targets and incentives are proposed in Table 9, below, for the first three years of the MRP.

- Incentives: The Commission envisions this PIM as initially being "upside" only and is considering an

[235]See Docket No. 2018-0141, Hawaiian Electric response to CA-IR-23(a), filed November 6, 2020.

[236]See Docket No. 2018-0141, Hawaiian Electric response to PUC-IR-110, filed November 6, 2020.

annual maximum reward of $2 million, calculated on a target revenue basis and allocated among the Companies using a 70/15/15 split.

Table 9: Proposed AMI Utilization PIM Targets and Incentives **Targets defined as number of customers by company with advanced meters installed and enabled to support advanced rates and programs, divided by number of total customers, by end of year.*			
Targets and Potential Rewards	**2021**	**2022**	**2023**
$1,400,000 HECO $300,000 HELCO/MECO	10%	25%	45%

Table 9 shows proposed targets for this PIM. These targets are shown as the percentage of total customers with AMI and enabled to support advanced rates and programs (as will be defined by the Post-D&O Working Group). For example, the 10% target in 2021 would equate to 30,636 of 306,368 total customers on Oahu.[237] These proposed targets recognize the delays in deployment experienced by the Companies to date, but are intended to drive improvement over the Companies' original deployment schedule by 2023. The Post-D&O Working Group may consider adopting these targets or may propose alternative targets, based on its discussions.

While the Commission expects that this metric and PIM structure will be refined by discussion in the Post-D&O Working

[237]See https://www.hawaiianelectric.com/about-us/power-facts.

Group, the Commission confirms that this PIM will be implemented as part of the PBR Framework, and the Post-D&O Working Group should focus its efforts accordingly.

The Commission looks forward to working with Parties in the years to come as the investment in AMI across the Companies' service territories continues to unlock new benefits for customers and the grid.

vi.

Online Customer Portal Development

The Commission had also explored the concept of a PIM to incent accelerated development of the Companies' online customer portal, the Utilities Customers E-Services Portal ("UCES").[238] In response to PUC-HECO-IR-53, the Companies clarified that as part of Phase 1 of their Grid Modernization Strategy (Docket No. 2018-0141), they are currently developing a "new customer energy portal" ("Energy Portal") that will contain the following features:

> With launch in April 2021, the Energy Portal will have functionalities for customers to:
>
> - View energy consumption, including indicators for time of use ("TOU")

[238]See PUC-Parties-IR-10, filed September 17, 2020.

usage tiers, temperature and humidity information;

- Compare usage against prior year, for customers who have a year of data;

- See a widget with highest bill in prior year;

- Analyze historical usage against other rates to identify possible savings;

- Perform what-if scenario planning, where customer[s] could modify their usage in the comparison to see what their bill would be;

- Download their data with Green Button Download My Data;

- Authorize third-party vendors to access their data with Green Button Connect My Data; and

- Set up threshold alerts and receive notifications on their energy use.

Additionally, the Energy Portal will include functionality for the Company to:

- Allow Company call center representatives to utilize the usage view for grid modernization advanced meter customers to assist with bill or energy usage inquiries, seeing interval usage as the customer does; and

- Manage Green Button Connect My Data, including registration, customer authorization and data exchange for third party vendors.

- Non-advanced meter customers registered in the Companies' Online Customer Service Center website will be able to view their monthly usage online once their register read is passed from SAP to the Energy Portal

> following their scheduled monthly manual read; however, some of the above functionality will not be available without interval data.[239]

The Companies' response goes on to describe the Energy Portal as "one-stop shop" that will:

> . . . [E]nable customers to log into a single portal to access all their online services such as account management which includes, but is not limited to, moving or stopping services, completing a payment arrangements [sic], submitting a high bill inquiry, signing up for preferences and outage (planned and unplanned) information, and applying for new and existing DER programs (Community Based Renewable Energy, Customer Grid Supply+, Smart Export, etc.).[240]

The Companies have indicated that they plan for the Energy Portal to become fully functional in April 2021.[241]

Upon review, it appears that efforts by the Companies are already underway as part of their Grid Modernization efforts in Docket No. 2018-0141 to implement a comprehensive, thorough online customer portal in the near future (i.e.,

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[239]Hawaiian Electric response to PUC-HECO-IR-53(a), filed November 13, 2020.

[240]Hawaiian Electric response to PUC-HECO-IR-53(c).

[241]See Docket No. 2018-0141, Letter From: K. Katsura To: Commission Re: Docket No. 2018-0141 – Hawaiian Electric Companies: For Approval to Commit Funs in Excess of $2,500,000 for the Phase 1 Grid Modernization Project and Related Requests; Supplement to June 30, 2020 Semi-Annual Status Report (Proportional Opt-Out Meter Deployment), filed September 30, 2020, Attachment 4.

the Energy Portal). Consequently, the Commission does not find that a PIM to incent acceleration of the UCES is warranted at this time. That being said, the Commission will closely monitor the Companies' progress in Docket No. 2018-0141 and may take further action in that proceeding to ensure the timely implementation of the Energy Portal as represented by the Companies.

vii.

Existing PIMs

As stated in the Phase 1 D&O, the development of Performance Mechanisms for the PBR Framework are intended to "complement the existing PIMs for Reliability, and Customer Service, and SSMs."[242] As referenced above, the Companies currently have two PIMs that support the Outcome of *Reliability*, which penalize the Companies for disruptions in service as measured by the System Average Interruption Duration Index ("SAIDI"), measuring the length of disruptions, and System Average Interruption Frequency Index ("SAIFI"), measuring the frequency of system interruptions (collectively the "SAIDI/SAIFI PIMs").[243] The Companies also have in place a PIM that supports

[242]Phase 1 D&O at 24.

[243]See Order No. 34514 at 30-32 and 45-58.

Customer Engagement by providing financial rewards and penalties for the Companies' Call Center performance, as measured by the percentage of calls answered within thirty seconds ("Call Center PIM").[244]

The Commission finds that the continued operation of the SAIDI/SAIFI and Call Center PIMs are reasonable and will complement the portfolio of other PIMs and SSMs approved in this D&O. As PBR continues to evolve, revisions to these existing PIMs may be considered as part of the Post-D&O Working Group, or as otherwise deemed appropriate by the Commission.

viii.

On-Going Incentives for Renewable Generation and Non-Wires Alternatives

As the Commission stated in the Phase 1 D&O, "[t]he [C]ommission believes SSMs provide an opportunity to incent the Companies to improve performance with respect to the priority Outcomes of *Grid Investment Efficiency*, by addressing utility capital bias, and *Cost Control*, by rewarding the Companies for pursuit of cost effective solutions to meet customer needs."[245]

[244]See Order No. 34514 at 32-39, 45-53, and 55-58.

[245]Phase 1 D&O at 50.

The Parties have proposed a variety of respective SSMs, but have expressed consensus over two in particular proposed by Ulupono: an SSM to incent the Companies to obtain competitively procured, utility-scale, low-priced, renewable energy; and an SSM to incent competitive procurement of grid services and non-wires alternatives ("NWAs").[246]

The Commission agrees that procurement of renewable generation and NWAs, at competitive costs, are objectives suitable for performance mechanisms and clarifies that the PBR Framework will allow for continued opportunities to earn rewards for both. Further, opportunities will not be limited to SSMs, but may also include the use of PIMs to incent efficient and cost-effective procurement. The specific details will be determined by the Commission in the context of specific proceedings, but will likely follow previous examples implemented by the Commission.

For example, SSMs may follow the format utilized in Stages 1 and 2 of Docket No. 2017-0352: competitive bids for renewable generation projects will be compared against benchmark price set by the Commission, with a portion of any savings going back to the Companies. Eligibility will be conditioned on firm

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[246]See Ulupono ISOP at 89, Hawaiian Electric ISOP at 215 and 219-220; COH ISOP at 27-38, and C&CH January 2020 Proposal at 22-23 (all supporting Ulupono's proposed SSMs); and Consumer Advocate ISOP at 116-117 (proposing an NWA SSM).

bids; i.e., the bidder will be responsible for any cost overruns. Self-build proposals by the Companies may be eligible for this SSM, provided their proposal is competitively selected and subject to the same firm bid requirement. Consistent with the Parties' support for Ulupono's proposals, this sharing ratio shall be between 20-30%.[247] The specific price benchmark, sharing ratio, and duration of sharing period[248] will be determined by the Commission on a case-by-case basis. Likewise, regarding NWAs, a similar structure would apply to the competitive procurement of NWAs.

As this structure is based on prior SSMs that the Commission has previously offered to the Companies,[249] the Commission and Companies should be able to draw on these experiences to efficiently review and implement similar SSMs and reduce the risk of unintended consequences.

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[247]Ulupono ISOP at 90.

[248]See Ulupono ISOP at 90 (proposing a two-year sharing period for the Renewable Procurement SSM and a five-year sharing period for the NWA SSM).

[249]See e.g., Docket No. 2017-0352, Order No. 35405, "Establishing a Performance Incentive Mechanism for Procurement in Phase 1 of the Hawaiian Electric Companies' Final Variable Requests for Proposals," filed April 6, 2018, and Order No. 36604, "Establishing Performance Incentive Mechanisms for the Hawaiian Electric Companies' Phase 2 Requests for Proposals," filed October 9, 2019 (while Docket No. 2017-0352 referred to these as "Performance Incentive Mechanisms," they operate as SSMs).

The Commission will also consider PIM proposals to incent competitive procured renewable generation and NWAs. While the Commission does not have any specific structure in mind at this time, it does not wish to foreclose this opportunity.

The Commission may implement, or the Companies may propose, a PIM or SSM in in the context of a particular proceeding.[250] Alternatively, if Parties elect to examine and develop such a PIM or SSM as part of the Post-D&O Working Group, the Commission will consider any such proposal at that time.

Although expressing openness to considering SSM and PIM proposals to support procurement of renewable generation and NWAs, the Commission is not persuaded, at this time, of the merit of the Companies' proposed MPIR SSM.[251] The Commission notes that the MPIR, itself (as modified in the new EPRM, discussed, supra), already represents a means to obtain additional revenues above the ARA, reserved for extraordinary projects. Incorporating an additional layer of financial incentive above the ARA

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[250]See e.g., In re Hawaiian Elec. Co., Inc., et al., Docket No. 2015-0389, "Order No. 37070, "Commencing Phase 2 of the Community-Based Renewable Energy Program," filed April 9, 2020, at 24 (stating that the Commission will implement a similar RFP-like process to foster procurement for the Community Based Renewable Energy program). Further, as noted, supra, the Commission intends to develop a refined version of the Grid Services PIM in the context of the DER proceeding, Docket No. 2019-0323.

[251]See Hawaiian Electric ISOP at 213-14.

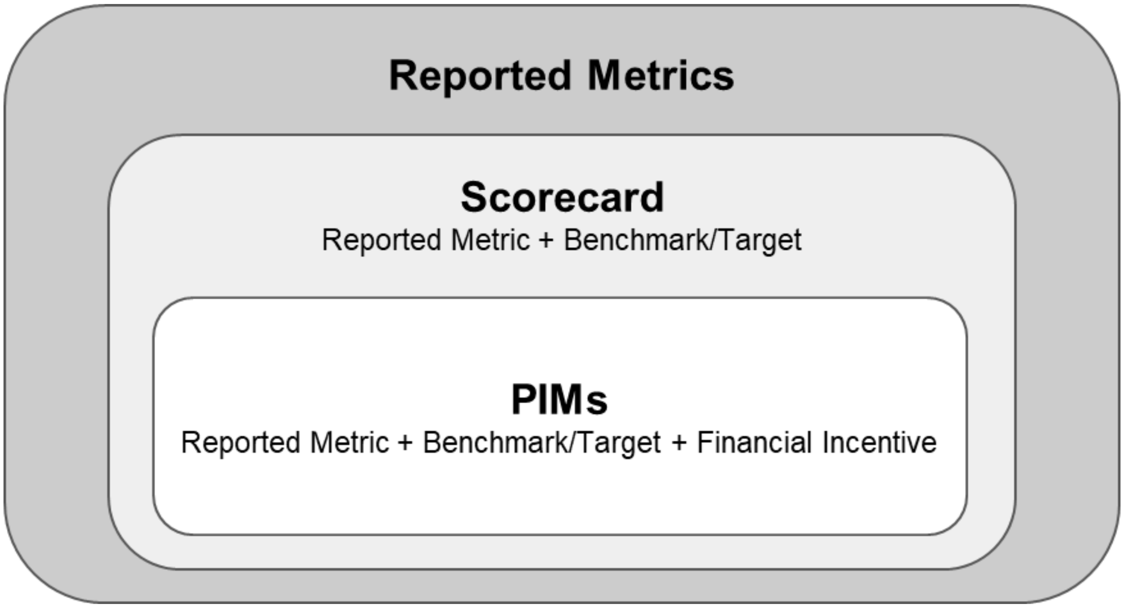
would not be appropriate under the circumstances. As noted in the EPRM Guidelines, see Appendix A to this D&O, among the criteria for eligible recovery through the EPRM is that the costs are "prudent and reasonable." While it is conceivable that the Companies could further ratchet down costs under an SSM, the Commission believes that under the new EPRM Guidelines, the Companies should be sufficiently incentivized to estimate their EPRM project costs at the reasonably lowest amount possible, in light of the risk of EPRM recovery being denied entirely.

2.

Scorecards and Reported Metrics

In the Phase 1 Staff Proposal, Commission staff described Performance Mechanisms using a framework of Reported Metrics, Scorecards, and PIMs, summarized in the illustration reproduced below:[252]

[252]Phase 1 Staff Proposal at 32, Figure 6.



As reflected in the illustration above, the three identified categories of Performance Mechanisms are organized in a nested fashion, with each subsequent tier including additional components to track, evaluate, and, in the case of PIMs, reward and/or penalize achievement of benchmarks or targets, in order to incentivize performance.

Briefly, Reported Metrics serve as a standard unit of measurement used to assess performance regarding an identified PBR Outcome,[253] whereas Scorecards effectively combine a Reported Metric with a specific benchmark or target to "encourage

[253]See Phase 1Staff Proposal at 31.

better achievement of regulatory outcomes than through Reported Metrics alone."[254]

During Phase 2, development of Scorecards and Reported Metrics was less robust, owing to the substantial commitment of time and resources to developing the other mechanisms of the PBR Framework (e.g., the ARA, EPRM, ESM, PIMs, SSMs, etc.).[255] While it was necessary to focus on developing these other mechanisms, the Commission reiterates that a portfolio of Scorecards and Reported Metrics will be included as part of the PBR Framework and that development of this portfolio will be a priority for the Post-D&O Working Group.

While not involving direct financial incentives, these non-revenue mechanisms are intended to drive further development of the PBR Framework during the MRP by facilitating the collection and reporting of relevant data (Reported Metrics) and evaluating the Companies' performance compared to Commission-established

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[254] See Phase 1 Staff Proposal at 33.

[255] C.f., Hawaiian Electric response to PUC-HECP-IR-30, "Background and Context to the Response to this Information Request," filed September 18, 2020 ("As the Commission is aware, due to the limited amount of time and resources of the Commission, Commission Staff and parties, a more significant portion of the time in this proceeding has been devoted to discussing and evaluating parties' proposed [PIMs] and [SSMs] due to the financial consequence of those proposals and the need to assess those proposals as a part of the overall comprehensive revenue evaluation that is the focus of the PBR process.").

benchmarks or targets (Scorecards). Due to the nascent nature of some of these metrics, attaching financial incentives at this time is premature, but with the accumulation of reported data promoting greater understanding of the Companies' performance, they may serve as the basis for future PIMs or SSMs.

The Commission observes that Phase 2 has yielded a wide range of proposed Scorecards and Reported Metrics,[256] and the Post-D&O Working Group should focus on narrowing and refining these proposals in preparation for implementing an initial portfolio of Scorecards and Reported Metrics, expected by June 1, 2021. To facilitate discussion, the Commission states its interest in focusing on the development of Scorecards and Reported Metrics for the following specific PBR Outcomes:

Scorecards:

- *Interconnection Experience*, which should at a minimum include Scorecards related to:
    - Time and cost to connect to the network, by DER and Independent Power Producer ("IPP").
    - Customer satisfaction results for both DER and IPP interconnections.
    - Truck roll-related/responsiveness times for both DER and non-DER customers.
- *Cost Control*, which should align with Post-D&O Working Group efforts to develop a future SSM for cost control

[256]See Hawaiian Electric response to PUC-HECO-IR-30, Attachments 1 and 2.

via reductions in fossil fuel consumption and purchased power.

- *Customer Engagement*, which should at a minimum include Scorecards related to:
    - Customer participation and retention in utility programs including but not limited to, TOU rates, Demand Response, and DER programs (in both absolute and percentage terms).
    - Customer access to and engagement with the customer portal and Green Button Connect My Data.
- *GHG Reductions*, which should, at a minimum, include Scorecards with annual declining targets related to:
    - Absolute emissions
    - Emissions intensity
- *Electrification of Transportation ("EoT")*
    - The Commission elevates this outcome area for Scorecard development in recognition of the importance of EoT to meeting GHG reduction goals and observing that the Parties broadly support EoT as an area for PIM development. Scorecards for this area should prioritize identifying metrics and targets, and collecting data to inform a future PIM that incents increased Electric Vehicle ("EV") adoption and rapid deployment of EV charging infrastructure, while maintaining grid investment efficiency and integration of EV charging to align with system needs.
    - The Commission acknowledges the broad support for the EoT PIM proposed by Ulupono,[257] and clarifies that in selecting PIMs for the initial portfolio, it was focused on addressing

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[257]See Ulupono ISOP at 79-88.

the prioritized Outcomes identified in the Phase 1 D&O,[258] which did not include *EoT*.[259]

- The Commission further notes that the Companies' EoT activities are expected to increase over the MRP, and that the Companies' currently have several EoT pilot proposals before the Commission. If approved and successful, such pilots may be considered for elevation to larger-scale programs. These activities and increased data availability will inform the most appropriate areas where incentives are required to align performance with desired outcomes.

Reported Metrics

- *Affordability*
- *Customer Equity*, which should include, at a minimum, reported metrics related to:
    - Number and/or percentage of customers entered into payment arrangements with the Companies.
    - Number and/or percentage of disconnections by customer class.
- *Capital Formation*
- *Grid Investment Efficiency*, which should, at a minimum, include reported metrics related to:

[258]See Phase 1 D&O at 45 (stating intent to focus development on PIMs to address Outcomes of *Customer Engagement, DER Asset Effectiveness*, and *Interconnection Experience*).

[259]Although Ulupono maintains that its EoT PIM will also address the Outcome of *Customer Engagement*, see Ulupono ISOP at 80, this would benefit a relatively small portion of customers, as EV ownership is largely concentrated within a relatively affluent sub-group of ratepayers. In light of other PIMs benefiting customers with DERs, another relatively affluent, and potentially overlapping sub-group of customers, the Commission elected to focus on a *Customer Engagement* PIM that addressed a broader customer base (i.e., the LMI EE PIM).

  - Total value ($) of deferred and/or avoided investments (e.g., T&D).

  - Total cost ($) of NWAs procured

- *Resilience*

- *DER Asset Effectiveness*: while this Outcome is also being addressed via a PIM, as discussed above, additional data is required to better understand how the Companies may be appropriately incented to effectively utilize DERs to meet system needs and/or avoid the need for acquiring less economical resources. Accordingly, the Commission prioritizes this Outcome for development of Reported Metrics to aid in data gathering for future PIMs and assessment of regulatory mechanisms. Reported Metrics for this Outcome should, at a minimum, include:

  - Percentage and total MW of DER systems capable of providing grid services.

  - Total MW of capable DER systems enrolled in grid services programs.

  - Total MW of DER systems enrolled in grid services programs being utilized to provide grid services (e.g., FFR, Load Reduction, Load Build).

  - MW of energy curtailed from DERs, including partial curtailment or power reductions.

The specific metrics identified as minimum requirements above are not intended to be an exhaustive list of areas for Scorecard and Reported Metric development, but rather, are metrics that the Commission views as necessary to include based on experience developing PIMs during Phase 2 of this proceeding.

The Commission notes that several of the Parties' proposed Scorecards and/or Reported Metrics aim to measure similar Outcomes, and that some proposed Scorecards and/or Reported Metrics may be similar to metrics already reported by the Companies in other proceedings. The Post-D&O Working Group should determine how best to report on each Scorecard and Reported Metric aligned with the above guidance and consistent with the PBR guiding principle of administrative efficiency, by avoiding duplicating efforts wherever possible, and the principle of utility financial integrity, by eliminating costs related to redundant or outdated reporting.

To further avoid duplicative efforts, the Post-D&O Working Group should consider whether specific reports already provided by the Companies in other dockets are suitable to serve as Scorecards or Reported Metrics under the PBR Framework, or whether such reports are no longer necessary and can be replaced.[260] If suitable, these may be recommended for inclusion or transfer to this docket, as these reports should be easy to compile and include in PBR reporting procedures.

Relatedly, the Commission instructs the Companies to update their website to include a webpage that will serve as a repository for the final, approved portfolio of Scorecards and

[260]The Companies state that they provided around 400 separate reports to the Commission in 2019. See Hawaiian Electric response to PUC-HECO-IR-30.

Reported Metrics. This webpage should also include all other reporting requirements, across all Commission proceedings, to streamline this reporting process and facilitate easy access to this information by stakeholders.[261] The Companies should have a preliminary version of this webpage for Commission and stakeholder review by June 30, 2021. Following feedback from the Parties, the Commission will approve the final version of the webpage. Thereafter this webpage should be updated throughout the MRP to timely reflect the Companies' performance, as well as to include any additions or modifications to Scorecards and/or Reported Metrics.

3.

Post-D&O Working Group

The Post-D&O Working Group is intended to serve as a forum during the MRP to continuously introduce, examine, and vet new Performance Mechanism proposals, as well as explore modifications to existing PIMs. This is intended to allow the PBR Framework to remain dynamic and continuously evolve in response to new opportunities and improved data.

[261]This webpage should incorporate existing Commission-ordered reporting already provided on the Companies' website, such as the key performance metrics webpage ordered in Docket No. 2013-0141.

For example, in addition to the PIMs and SSMs approved above, a variety of other Performance Mechanisms (PIMs, SSMs, Scorecards, and Reported Metrics) were proposed and discussed during Phase 2. While promising, lingering concerns and lack of time prevented them from being sufficiently developed for approval in this D&O.[262] However, interest remains, and the PBR Framework will incorporate a Post-D&O Working Group to continue discussing and vetting Performance Mechanisms proposals raised in Phase 2, with the possibility of implementation of select mechanisms during the MRP.

The Post-D&O Working Group is envisioned as being a party-led process, with the Commission attending as participants/observers, until/unless a PIM (or other Performance Mechanism) proposal is determined to be ripe for submission, at which point the Commission will lead the review of the proposal. That being said, the Commission will initiate and lead the initial Post-D&O Working Group in the months following this D&O to address the following proposals the Commission prioritizes for near-term development ("Prioritized Performance Mechanisms"):

[262]C.f., Blue Planet ISOP at 66 (stating that "finalizing the entire PIM portfolio during the current Phase 2 process may not be feasible or advisable.").

- Resolving final details for the Interconnection Approval PIM, LMI Energy Efficiency PIM and AMI Utilization PIM; and

- Finalizing a portfolio of Scorecards and Reported Metrics.

Further guidance to focus the Post-D&O Working Group's development of Scorecards and Reported Metrics is provided in Section IV.B.2, supra.

The Commission clarifies that the Prioritized Performance Mechanisms are not intended to be an exhaustive list of proposals that may considered in the post-D&O working group.[263]

In light of the post-D&O work necessary to implement the PBR Framework, see Section IV.E.1, infra, the Post-D&O Working Group will commence in February of 2021, to allow initial time and attention to address the development of proposed the PBR implementation tariffs. At this time, the Commission envisions the following schedule for the immediate post-D&O working group, as set forth in Table 10, below:

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[263]For example, the Commission notes that several of the Parties have proposed a PIM to address reductions in GHG emissions. See Blue Planet ISOP at 71-72; and C&CH January 2020 Proposal at 23-24. Further, the Commission continues to maintain interest in exploring an SSM to incent efficient additions and utilization of renewable resources to replace fossil fuel generation and reduce related costs. See PUC-Parties-IR-01 through -03, issued on July 24, 2020.

Table 10: Post-D&O Working Group Schedule	
February 9, 2021	Working Group convened with a workshop and review of Prioritized Performance Mechanisms (i.e., Interconnection Approval PIM, LMI Energy Efficiency PIM, AMI Utilization PIM and portfolio of Scorecards and Reported Metrics).
February 23, 2021	Working Group meeting.
March 9, 2021	Working Group meeting.
March 16, 2021	Refined proposals addressing Prioritized Performance Mechanisms submitted by Parties (and potentially Commission staff).
March 23, 2021	IRs submitted in response to proposals.
April 2, 2021	Responses to IRs.
April 9, 2021	Parties may submit refined proposals, based on IR responses.
By April 30, 2021	Commission order addressing Prioritized Performance Mechanisms.
May 2021	• Companies to submit Prioritized Performance Mechanisms tariff language for Prioritized Performance Mechanisms. • Commission to review and approve tariffs, expected to take effect June 1, 2021.
June 30, 2021	Companies share proposed webpage to post approved Scorecards and Reported Metrics with Parties and Commission for feedback and approval. Following approval of webpage, this webpage should be updated throughout the MRP to timely reflect the Companies' performance, as well as to include any additions or modifications to Scorecards and/or Reported Metrics.

Post-June 2021	• Transition to Party-led process. • Working Group to meet as determined by Parties or Commission staff, as necessary, to continue development of any PIMs, SSMs, Scorecards, and/or Reported Metrics that show promise of being implemented in near-term during the MRP. • Review and approval process for proposals elevated from the Post-D&O Working Group to the Commission for consideration may repeat itself, as necessary, to continue development of any PIMs, SSMs, Scorecards, and/or Reported Metrics that show promise of being implemented during the MRP.

C.

Pilot Process

In addition to the additional revenue opportunities discussed above, the Commission is including a Pilot Process to foster innovation by establishing an expedited implementation process for pilots that test new technologies, programs, business models, and other arrangements. This is intended to support initiatives by the Companies to test new programs and ideas quickly and elevate any successful pilots for consideration of full-scale implementation.

In the Phase 1 Staff Proposal, the concept of an expedited process for pilot projects was introduced, under which pilots "that test new technologies, customer engagement programs, business models, and other arrangements[,]" would be expedited, to help drive innovation.[264] While not expressly addressed in the Phase 1 D&O, during the Working Group Process, the Commission invited the Parties to consider developing proposals for an expedited pilot process.[265]

In response, the Companies included in their ISOP a conceptual description of an expedited pilot process.[266] This proposal was later supplemented by the Companies' responses to Commission information requests,[267] as well as the Companies' subsequently developed pilot framework for their EoT initiatives ("EoT Pilot Framework")[268] (the EoT Pilot Framework was introduced

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[264]Phase 1 Staff Proposal at 47. See also, id. at 49 ("In the nearer term, [Commission staff recommends the development of an expedited pilot implementation process, which could result in several leading-edge projects without the limitations of traditional program approval.").

[265]See Hawaiian Electric ISOP at 220-21 (referring to Commission guidance provided at the March 2020 Working Group meeting).

[266]See Hawaiian Electric ISOP at 220-27.

[267]See Hawaiian Electric response to PUC-HECO-IR-18, filed August 3, 2020.

[268]See Order No. 37374, "Notifying the Parties of the Transfer of the Electrification of Transportation Innovative Pilot Framework into Docket No. 2018-0088," filed October 16, 2020; and Letter From: D. Matsuura To: Commission Re: Docket No. 2018-0088 – Instituting a Proceeding to Investigate Performance-Based Regulation; Transferring EoT Innovative Pilot Framework Into Docket No. 2018-0088, filed October 29, 2020.

in Docket No. 2018-0135, the Commission's investigation into an EoT strategic roadmap for the Companies, but the guidance for the EoT Pilot Framework was based on elements drawn from the pilot program framework for Green Mountain Power in Vermont, which was also referenced as a guiding source for a PBR pilot process in the Phase 1 Staff Proposal).[269]

Upon review of the record, including the Companies' EoT Pilot Framework and clarifications on a pilot process for the PBR context,[270] the Commission approves an expedited process for reviewing pilot projects ("Pilot Process") as part of the PBR Framework. The Commission notes that the Companies requested additional time to modify the EoT Pilot Framework for a broader context,[271] but believes that the record supports approving an expedited Pilot Process in full, as outlined below, at this time. In doing so, the Commission largely draws from the Companies' proposals, including its briefing in this proceeding, as well as the EoT Pilot Framework, but makes several modifications to better

[269]See EoT Pilot Framework at 5; and Phase 1 Staff Proposal at 47-48.

[270]See Hawaiian Electric response to PUC-HECO-IR-55, filed December 4, 2020.

[271]See Hawaiian Electric response to PUC-HECO-IR-55(a)(requesting a 3- to 6-month period to "establish this Company-wide framework[.]").

balance the costs and benefits of the Pilot Process between the Companies and its customers.

The Pilot Process is described as follows:

Governance and Approach. The Commission agrees with the Companies that flexibility is important to the success of the Pilot Process.[272] Consequently, the Companies may exercise flexibility in selecting pilot vendors and need not strictly adhere to traditional contract bidding and selecting processes.[273] As stated by the Companies, "[p]iloting is successful when testing and evaluation can happen fast and at a small enough scale to reduce technical and financial risk."[274] Although this presents some risk, the Commission finds that it is balanced, under the circumstances, by the speed and flexibility this will provide the Companies to explore and execute contracts for innovative new programs and services, as well as by the cap on costs allowed under the Pilot Process (discussed below).

Concomitantly, the traditional nature and scope of Commission review may not be appropriate for expeditiously reviewing pilots. As a result, the Pilot Process will afford the Companies with a greater degree of freedom to pursue pilots,

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[272]See Hawaiian Electric ISOP at 221.

[273]C.f., Hawaiian Electric response to PUC-HECO-IR-18(c).

[274]Hawaiian Electric ISOP at 224.

with oversight by the Commission tailored to provide the Companies with greater discretion to proceed with pilots, while maintaining Commission approval for pilot costs, as well as requiring reporting on implementation of approved pilots. Relatedly, the Pilot Process shall be subject to a total annual cap of $10 million. Requests to proceed with a pilot or annual portfolio of pilots in excess of this capped amount must be expressly approved by the Commission.

Eligibility. Pilot projects should:

- Involve products or services beyond the sale of basic electric service and align with an established regulatory goal, such as those established within the PBR Framework;[275]

- Seek to leverage funding from alternative sources, e.g., grants or third-party investments,[276] to minimize impacts to customers;

- Incorporate a requirement for pilots involving non-local vendors and larger sole-sourced vendors (i.e., vendors with more than 100 employees) to participate in cost-sharing for the pilot (e.g., in-kind contributions, such as engineering or project management support);[277]

- Incorporate preference for pilot partnerships with Hawaii-based vendors (e.g. contracting for services and/or technologies from local businesses);

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[275]See EoT Pilot Framework at 12.

[276]See Hawaiian Electric response to PUC-HECO-IR-18(b) (the Commission assumes the Companies intended for their response to read that they would not seek recovery in a scenario where a pilot was funded by grants or third-party investments).

[277]See Hawaiian Electric response to PUC-HECO-IR-18(c).

- Provide estimates of Net Present Value ("NPV") with considerations such as new sources of revenue, cost savings over a defined time period, or other metrics such as a reduction in GHG and contributions to State policy goals via reduction in imported fossil fuels;[278]

- Provide the Commission, Consumer Advocate, and key stakeholders with reasonable access to data (e.g., to assess key performance metrics);[279] and

- Incorporate participant customer surveys or measurement and verification evaluation to measure progress against program success criteria and metrics.[280]

Process. The Pilot Process will feature the two primary activities drawn from the EoT Pilot Framework: an initial "Workplan Development" phase, during which areas of interests are identified and scoped, so as to inform the subsequent "Implementation" phase, during which specific pilot proposals are submitted for expedited review by the Commission and implemented, upon approval, by the Companies.

The Pilot Process will begin with Workplan Development, where the Companies will invite the Commission, Consumer Advocate, and other interested stakeholders to collaboratively "identify an

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[278]EoT Pilot Framework at 12.

[279]EoT Pilot Framework at 12. Additional examples of key performance metrics that may be considered include data addressing customer satisfaction, demand and energy impact, and progress toward the State's RPS. See id. at 14.

[280]EoT Pilot Framework at 13.

initial set of 5-10 areas of collaboration[,] taking into consideration the alignment and leveraging of the Companies['] prior related strategic plans, including [Integrated Grid Planning ('IGP')], Grid Modernization Strategy ('GMS'), [RPS] resource procurements, Customer Energy Resources ('CER') Strategy, and the EoT Strategic Roadmap."[281]

This will lead to the development of a portfolio of pilot concepts that may be refined and introduced as specific pilot proposals as part of the Implementation phase. There is no fixed time for completion of the Workplan, but it will be submitted to the Commission upon completion and subject to Commission review and feedback prior to the commencement of the Implementation phase. The Workplan should provide as much information and detail as possible, so as to support the Commission's review process, described below.

Following submission of the Workplan, the Companies may proceed with pursuing pilots for implementation, consistent with the portfolio described in the Workplan.[282] Once a pilot has been

[281]Hawaiian Electric ISOP at 223.

[282]The Commission observes that the Companies have already submitted pilot proposals this year. See Docket No. 2020-0098 (EBus Make-Ready Infrastructure Pilot Project); Docket No. 2020-0152 (Application for EV tariffs for Schedules EV-J and EV-P); and Docket No. 2020-0202 (Charge Ready Hawaii Pilot Project). The Commission intends to continue with its review

developed, the Companies shall submit written notice ("Notice") to the Commission. At a minimum, the Notice shall include "a narrative explanation of the pilot project, key customer benefits (participants and non-participants) where applicable, eligibility requirements, subscriber cap (if applicable), lifecycle GHG analysis (if applicable), an estimate of the pilot costs and forecasted revenues (if applicable), project timeline, [proposed] reporting requirements, and [proposed] success criteria."[283] More specifically, the Notice shall address:

- Expected outcomes of the pilot project (e.g., added or improved services), including methods and metrics for measuring success and risk of the pilot project, which may be used to evaluate progress throughout the course of the pilot.

- How the outcomes of the pilot project are aligned with State energy goals and Commission orders, including, but not limited to: Docket No. 2018-0088 (this proceeding), Docket No. 2018-0135 (EoT Strategic Roadmap); Docket No. 2019-0323 (DER investigation), Docket No. 2018-0165 (IGP investigation), and the State's energy efficiency efforts.

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of these pilot project applications concurrently with the Companies' development of the Workplan (i.e., review of the pending pilot applications will not be affected by the development of the Workplan). However, if approved, the pending pilot projects will still be subject to the Pilot Process, including reporting requirements, and pilot costs will be counted toward the annual pilot process cost cap.

[283]EoT Pilot Framework at 9.

- Areas of potential overlap with other existing project(s)/program(s) and, if so, how such overlap will be addressed by the pilot project.[284]

The Commission shall review the Notice and issue an order, approving, denying, or modifying the proposed Pilot, within forty-five (45) days of receiving the Notice. To facilitate this expedited review, the Companies should keep the Commission and any relevant stakeholders, such as the Consumer Advocate, apprised of prospective pilot proposals and seek to incorporate stakeholder and Commission input into the Notices.

Any discontinuance of a pilot or material changes to the pricing, terms, or conditions of the pilot will be filed with the Commission forty-five (45) days in advance for Commission review, with written notice of the proposed changes also sent to pilot participants. The Commission may approve, modify, or deny the proposed changes. If the Commission does not take affirmative action during the 45-day window, the changes are considered approved. Following issuance of the Commission's order addressing the pilot changes, the Companies shall provide pilot participants with notice of the Commission's ruling and any changes to the pilot program.

[284]See EoT Pilot Framework at 11.

Duration. The Pilot Process shall be available throughout the MRP, and may be extended at the Commission's discretion. Regarding specific pilots, the Commission acknowledges the "dynamic nature of technology trends," and recognizes that "there may be pilot projects with varying levels of complexity and scope."[285] Accordingly, the Commission will review each proposed pilot's duration, as set forth in each Notice, on a case-by-case basis.

Review and Reporting. The Companies will file an annual comprehensive report covering all active pilots ("Pilot Update") by March 31 each year.[286] The Pilot Update should, at a minimum, contain the following information:

- Implementation schedules and progress relative to the pilot's objective and key performance metrics;
- Pilot impacts on underserved communities;
- Pilot costs and revenues (if applicable), including cost analysis per subscriber, quantitative and qualitative benefits(for both pilot participants and non-participants), and an NPV analysis
- Qualitative description of the pilot and customer benefits; and

[285]EoT Pilot Framework at 9.

[286]At this time, the Commission is considering opening a docket to serve as a repository for Pilot Process-related filings, such as the Workplan, Notices, and Pilot Updates, as well as to address Pilot Process-related disputes, similar in operation to Docket No. 2017-0352.

- Any proposed changes to material aspects of the pilot, such as program pricing, terms or conditions, eligibility requirements, changes to the implementation schedule, or program cancellations (including reason for the cancellation).[287]

In addition to providing an update on ongoing pilot programs, the Pilot Update may include final reporting on completed projects, as applicable.[288] "The final report may include the utility's marketing efforts and expenses incurred, methods for analyzing impacts, cost-effectiveness, and customer retention[,]" and must include reporting on "challenges and lessons learned, process improvements, a determination of the success of the pilot, and any future permanent implementation plans based on an evaluation against the metrics established."[289]

Consistent with the Companies' recommendation, the Commission will allow a single, consolidated report at this time to facilitate efficiency and consistency.[290] While the Companies appear to have contemplated reporting on pilots on a biennial basis,[291] the Commission believes that more frequent

[287] See EoT Pilot Framework at 15-16.

[288] See EoT Pilot Framework at 11.

[289] EoT Pilot Framework at 16.

[290] See EoT Pilot Framework at 10-11.

[291] See EoT Pilot Framework at 15.

review is appropriate, in light of the pilot costs borne by customers and the value of pilots that may be accruing.

That being said, no Pilot Update will be required for 2021, as it is expected that no new pilots will yet be in place, given the PBR tariff implementation details and Workplan process that must be accomplished first.[292]

Cost Recovery

At the time the Notice is submitted, the Commission shall conduct an expedited review, not to exceed forty-five (45) days, and issue an order addressing the Notice. The Notice shall include the pilot's estimated costs and revenues (if applicable). If the Commission approves the Notice, the order will include authorization to commit a certain amount towards the pilot program, similar to the operation of the Commission's review under General Order No. 7.

Subsequently, the Companies shall submit the costs and revenues (if applicable) associated with the pilot as part of the next Pilot Update, which will be reviewed in the spring of each year as part of the Commission's spring review of adjustments to the Companies' target revenues (described in Section IV.E.3, infra.). The Commission will determine, at that time, the amount

[292]See EoT Pilot Framework at 11 (providing for no annual report in 2021, "as new pilot(s) are being established.").

of pilot costs that may be recovered for that year. It is expected that recoverable costs will be consistent with those previously approved in the order addressing the Notice, but will take into account considerations such as cost overruns, changes to the pilot, offsetting revenues generated by the pilot, etc. The Companies will continue to submit the pilot's costs and revenues (if applicable) as part of their Pilot Update, and approved costs will be incorporated as adjustments to target revenues for the duration of the pilot.

Although different than the process proposed by the Companies, the Commission finds that this represents a reasonable balance between giving the Companies flexibility and discretion to pursue pilot projects with expediency and ensuring that associated costs are reviewed prior to collection. Reviewing pilot costs as part of the Commission's annual spring review of the Companies' target revenues also has the simplicity of allowing the Commission to incorporate any approved pilot costs as a direct adjustment to the Companies' target revenues, which are comprehensively reviewed and adjusted at this time, rather than relying on a separate mechanism, such as the REIP surcharge or the EPRM, to accomplish the same effect.[293] Further, the Commission notes that this process

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[293]See EoT Pilot Framework at 13 (stating that "the revenue recovery mechanism will depend on the characteristics of the

is consistent with the cost review process approved by the Vermont Public Utility Commission for the pilot framework approved for Green Mountain Power.[294]

Cost recovery will be allowed for the duration of the pilot, pursuant to the schedule approved by the Commission;[295] however, should the pilot be extended beyond its initial term, or if the pilot is expanded for larger-scale implementation, the nature and details of the pilot's cost recovery will be re-visited by the Commission.

Pilot Expansion. At the conclusion of the scheduled operation of the pilot, as previously approved by the Commission, the Companies may seek to expand the pilot on a larger-scale basis. The Commission agrees that "[p]ilots that can yield benefits for electric utility customers should be allowed to continue after the

pilot[,]" and that "[w]hile the REIP will be the likely recovery mechanism, other mechanism such as the [MPIR] adjustment mechanism and [RAM] cap will be considered where applicable.").

[294]See In re Green Mountain Power Corp., Case No. 18-1633-PET, Order entered May 24, 2019, at 31 ("GMP must reflect the estimated costs and revenues of Innovative Pilots developed under the Plan in any annual base rate filing during the term of the Plan if those costs are not already included in rates at the start of the Plan. GMP is required to include a schedule setting forth the costs and revenues of all Innovative Pilots offered as well as known and measurable information supporting the addition to rate base, which will be subject to Department review and Commission approval.").

[295]See Hawaiian Electric ISOP at 226.

pilot period[,]" subject to Commission approval.[296] The Commission further agrees with the importance of maintaining continuity during this transition, so as to avoid confusion and potential defection from the pilot program.[297]

To minimize confusion, the Companies shall notify the Commission in advance of any pilot programs it wishes to submit for extended operation and/or expanded scope. The Companies will already be providing an annual review of their pilot programs as part of the Pilot Update, so this should be a natural extension of this reporting requirement. No later than one year prior to the scheduled termination of a pilot project, the Companies shall submit a request to the Commission seeking to extend and/or expand the pilot project, if so desired. The request shall contain a description of the proposed extension and/or expansion of the pilot, with supporting evidence, including proposed schedules, estimated costs and benefits, and a proposed method for cost recovery. The Commission will address each such request on a case-by-case basis. The one-year advance notice should provide sufficient time to resolve the Companies' request and avoid significant disruption to a successful pilot's operation.

[296]Hawaiian Electric ISOP at 226-27.

[297]See Hawaiian Electric response to PUC-HECO-IR-18(e).

The Companies shall develop a written Pilot Process consistent with the above for the Commission's review. Submittal and Commission approval of the written Pilot Process shall occur prior to the commencement of the Workplan process described, above.

D.

Safeguards

1.

Earnings Sharing Mechanism

As stated in the Phase 1 D&O, the Commission intends to include in the PBR Framework an ESM to "share" utility earnings and costs when the Companies' ROE deviates from a pre-determined level, subject to an initial deadband, within which there is no sharing.[298] Fairly early during the Working Group process, the Parties coalesced around a general consensus for a proposed ESM, with many utilizing the Companies' existing authorized ROE as the pre-determined target. Proposed deadbands range from +/- 50 to 200 basis points, with sharing tiers expanding outward in tranches of between 100 to 200 basis points, with corresponding sharing ratios of 25/75, 50/50, and an extreme sharing split ranging from

[298] See Phase 1 D&O a 32.

75/25 to 95/5 (customers/Companies).[299] Of the Parties, Blue Planet was unique in arguing against the inclusion of an ESM in the PBR Framework, voicing concern that the ESM's reliance on ROE would persistently anchor the PBR Framework to a COSR metric and dilute the incentives provided by the MRP.[300] Notwithstanding these reservations, Blue Planet offered a series of alternative considerations, including using a non-ROE metric such as Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"), incorporating a wide deadband ("no less than the range of variation that the utility has historically experienced under COSR"), and applying the ESM less than once a year.[301]

Upon reviewing the record, the Commission will proceed with incorporating an ESM into the PBR Framework. As a preliminary matter, the Commission observes that an ESM has been proposed as an integral part of nearly every Party's PBR proposal. Despite Blue Planet's opposition, the Commission continues to believe that "a well-designed ESM will maintain the utility's financial integrity and reduce risk to the [Companies'] bondholders and shareholders, which will have a corresponding reduction in the

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[299]See Companies ISOP at 127; Consumer Advocate ISOP at 68; Ulupono ISOP at 39; and C&CH January 2020 Proposal at 18.

[300]See Blue Planet ISOP at 20-23.

[301]Blue Planet ISOP at 28-29.

cost of capital, benefitting all customers."[302] Particularly during these initial stages of PBR, it is important to provide reassurance to financial markets that the transition to PBR will not be attended by extreme results. An ESM will help alleviate concerns by providing assurances that significant decreases in earnings will be mitigated; likewise, in the event incentive mechanisms are initially too generous, excessive earnings by the Companies will be shared with their customers.

After reviewing the various proposals put forth by the Parties, the Commission, rather than adopt any specific proposal, establishes its own ESM (though, in doing so, the Commission largely draws from the Parties' suggestions):

- The target ROE shall be the current authorized ROE for the Companies (which is 9.50% for all of the Companies[303]).

- A deadband of 600 basis points (300 basis points in both directions) within which there is no sharing of earnings/costs.

- A sharing tier over the next 150 basis points, in which earnings/costs are split 50-50 between the Companies and ratepayers.

- A second sharing tier beyond which earnings/costs are split 90-10 between ratepayers and the Companies.

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[302]Phase 1 D&O at 33.

[303]See No. 2019-0085, D&O 37387 at 59; Docket No. 2018-0368, D&O 37237 at 83; and Docket No. 2017-0150, D&O 36219 at 203.

- Shared costs to the Companies shall be collected in the following year as part of the Spring Revenue Report, effective June 1 (see Section IV.E.3, infra.).

- Shared earnings to ratepayers shall be returned as a bill credit in the following year as part of the Spring Revenue Report, effective June 1.

The Commission's ESM is illustrated below:[304]

Table 11: Earnings Sharing Mechanism						
<5.00% 90/10 sharing	<6.50%-5.00%% 50/50 sharing	<9.50%-6.50% No sharing	9.50%	>9.50%-12.50% No sharing	>12.50%-14.00% 50/50 sharing	>14.00% 90/10 sharing

Notwithstanding the above, the Commission understands Blue Planet's concerns and agrees that, ideally, the PBR Framework will properly align utility incentives and operations such that the ESM is used sparingly. This sentiment is reflected in the wide deadband placed around the target ROE of 9.50%. As stated above, this mechanism is being approved in recognition of the unprecedented transition of the Companies into a progressive and rapidly evolving new regulatory framework. Conservative safeguards are being implemented in an abundance of caution; as the Companies, Commission, and markets become more familiar with PBR, the Commission will re-examine the issue of safeguards to determine what is appropriate and necessary in light of the attendant risks.

[304]Sharing ratios reflect ratepayers/Companies.

Relatedly, the Commission appreciates Blue Planet's efforts to craft an alternative ESM and is intrigued by some of its suggestions, such as utilizing an alternative metric to ROE, such as EBIDTA. At this time, the Commission finds that ROE is still the preferred metric for the ESM, particularly given the novelty of the PBR Framework, but may consider exploring an alternative metric for the ESM in future PBR iterations.

2.

Re-Opener

In the Phase 1 D&O, the Commission stated that it would consider "off-ramp" provisions to review PBR mechanisms during the MRP under specific circumstances or conditions.[305] This has generated a variety of responses from the Parties, ranging from what specific events should trigger activation of an "off-ramp"[306] to whether such mechanisms are necessary in light of the other PBR safeguards in place (e.g., the ESM and annual reviews).[307]

As a preliminary matter, the Commission believes that a contributing factor to the range of perspectives arises from the

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[305]Phase 1 D&O at 33.

[306]See Hawaiian Electric ISOP at 129-30; COH ISOP at 10; and C&CH January 2020 Proposal at 18-19.

[307]See Consumer Advocate ISOP at 72-73; and Ulupono ISOP at 53-55.

misleading use of the term "off-ramp," which may intuitively signal the cessation of a PBR mechanism or the abandonment of the entire PBR Framework. The Commission clarifies that this not the intent of this mechanism – rather, its purpose is to provide the Companies with an opportunity to petition the Commission so that the Commission might review various PBR mechanisms and consider modifications during the MRP, outside of its regularly scheduled annual review cycle. Termination of the PBR Framework would be the most drastic of remedies and would only be warranted in the most extreme situation and only after Commission review and investigation.

As a result, the Commission has re-designated this mechanism as a "Re-Opener," to better convey the intent of this mechanism.[308] Upon the occurrence of a triggering event, of which the Companies will timely provide the Commission with written notice, the Commission will review the PBR Framework to determine which, if any, PBR mechanisms may be responsible and whether any modifications to the PBR Framework are appropriate. Based on its review, the Commission will exercise its discretion to fashion a

[308]See Blue Planet ISOP at 40 ("Blue Planet recommends that the PBR regime include a *reopener* provision that allows the Commission and parties to revisit the PBR regime and consider what changes may be needed under the circumstances – in contrast to an 'off-ramp' that may suggest an automatic ability to terminate or exit from PBR outright.")(emphasis in the original).

remedy deemed appropriate under the circumstances. Nomenclature aside, this is consistent with the sentiments expressed by the Parties.[309]

Explicit triggering events, which the Companies may use to request a Re-Opener are: (1) the Companies' credit rating outlook indicates a potential credit rating downgrade below investment-grade status, as determined by Moody's, Standard & Poor's, or Fitch credit rating agencies; or (2) the Companies' actual ROE enters the outermost sharing tiers of the ESM (either upside or downside). Again, this is largely consistent with the Parties' proposals,[310] and balances the reassurance

[309]See Hawaiian Electric ISOP at 130 ("It an off-ramp is triggered . . . then the Commission by order on its own motion, or upon petition by the Company, will determine the appropriate remedy."); Blue Planet ISOP at 40 (quoted in n. 200, supra); and COH ISOP at 10 ("Formal PBR Review would create a docket proceeding to evaluate the necessity of tweaks or full-scale reforms to ensure the new regulatory framework functions as intended.").

[310]See Hawaiian Electric ISOP at 129-30 (proposing "two ROE triggers: (i) if a utility's ROE is 500 basis points above or below the allowed ROE in a single year and (ii) if a utility's ROE is 300 basis points above or below the allowed ROE during any consecutive two years."); Blue Planet ISOP at 42 ("Specifically, a reopener should apply 'in the event of a credit rating downgrade, or if such a downgrade is imminent.'") (emphasis in the original); C&CH January 2020 Proposal (providing, as an example off-ramp trigger, "a precipitous decline in ROE or credit quality, or other suboptimal outcomes[.]"); and COH ISOP at 10 (listing an imminent credit downgrade, deviations of >15% to actual earnings, and degradation of utility service reliability and safety as suggested triggering events).

provided by safeguard mechanisms to address unforeseen situations with concerns that excessive safeguard mechanisms may dilute the effectives of the PBR mechanisms.

In this regard, the Commission is deliberately establishing a limited number of triggers in light of the other safeguards incorporated into the PBR Framework, notably the ESM. Combined with the annual review cycle, the PBR Framework provides a robust safety net, and the Commission does not anticipate the need to resort to Re-Openers. That being said, while the Companies' opportunities to applying for a Re-Opener are limited by the explicit triggering events above, the Commission retains discretion to examine any PBR mechanism(s) at any time.

E.

Implementation

1.

Tariff Review

In order to implement the PBR Framework approved in this D&O, the Companies will need to develop tariffs to reflect these new PBR mechanisms and amend or replace several existing tariffs, including one or more new tariffs to implement the PBR Framework provisions, as well as amendments to the RBA Provision tariff, MPIR Provision tariff, PIM tariffs, and RAM Provision tariff, consistent with the provisions in this D&O. In particular, the RAM Provision tariff will become ineffective at the time the PBR implementation tariffs go into effect, which is expected to be June 1, 2021. Recognizing that the existing RAM Provision tariff requires filing of information in support of a RAM Revenue Adjustment by March 31, 2021, and that the ARA Adjustment, rather than any RAM Revenue Adjustment, will become effective on June 1, 2021, the Companies, as part of the tariff working group described in this section, shall file a proposed RAM Provision Tariff, amended to appropriately remove and/or adjust filing requirements for the March 31, 2021 RBA Review Transmittal filing. The modified RAM Provision Tariff will be identified for expedited review so as to be addressed ahead of the Companies' March 31, 2021 RBA Review Transmittal filing.

In order to facilitate this process in a timely and organized manner, the Commission will establish a schedule for tariff development, review and comment, approval, and effect, as set forth in Table 12, below:

Table 12: Tariff Development Schedule	
January 2021	• The Commission will oversee a working group to develop and vet tariff language. • While participation in this working group is otherwise voluntary, the Companies and Consumer Advocate's participation is requested. • Commission staff may participate as well and may take action to help facilitate clear understanding and effective tariff language development.
February 15, 2021	Companies submit draft tariffs for Commission review (e.g., tariffs for implementing ARA, modified RBA and RAM tariffs, etc.).
March 8, 2021	Other Parties may submit comments on the Companies' draft tariffs.
By April 1, 2021	Commission will issue order addressing draft tariffs (RAM Provision tariff on expedited review ahead of March 31, 2020).
By April 30, 2021	Companies submit final tariffs consistent with Commission's order, effective June 1, 2021.

While this schedule is subject to modification by the Commission, in its discretion, the Commission does not anticipate any significant changes. Due to the uncertainty regarding the COVID-19 pandemic and the State's response, the Commission expects that the tariff working group meeting(s) will be held virtually. As noted above, Commission staff may participate to help facilitate this process, which may include the convening of an informal technical conference, if necessary. The Commission will provide the Parties with electronic notice no later than one week in advance.

2.

Decoupling

In the Phase 1 D&O, the Commission indicated its preference for continuing the RBA, subject to any necessary modification to accommodate implementation of the PBR Framework.[311] This concept has not been challenged by the Parties,[312] although the Companies have proposed modifying the RBA to reduce lag and "streamline the existing accrual, recovery, and reconciliation process."[313]

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

[311]Phase 1 D&O at 35-36.

[312]See Consumer Advocate ISOP at 78-79; and Ulupono ISOP at 53.

[313]Hawaiian Electric ISOP at 42.

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.

In order to effectuate a smooth transition to the PBR Framework, and minimize disruption to the processes for determining the Companies' target revenues, the Commission has developed the following process.

In light of the post-D&O work necessary to vet and finalize the tariffs to implement PBR, discussed in Section IV.E.1, supra, the Companies' "current" decoupling process shall continue, with the following modification. The Companies shall submit filings in February and March in 2021, followed by the Commission's existing review in April and May 2021. The Commission shall issue an order in May 2021 approving an adjustment to the Companies' target revenues effective June 1, 2021, but based on the ARA and provisions in this D&O, rather than any 2021 RAM Revenue Adjustment.

The RAM Provision tariff for each Company will expire and become ineffective upon replacement by the new PBR tariffs, scheduled to occur on June 1, 2021, as set forth in the Table 12, supra. As provided in the existing RAM Provision tariff, current effective target revenues will continue to be in accord with the 2020 RAM Revenue Adjustment implemented for the June 1, 2020, through May 31, 2021 period. Beginning on June 1, 2021, effective target revenues will be determined in accordance with the ARA formula and as provided in this D&O.[314] As noted above, the initial revenues that will be adjusted by the ARA at the beginning of the MRP will be the existing effective allowed revenue for each of the Companies as of the last date before the pertinent PBR tariffs take effect.

Commencing June 1, 2021, the Annual ARA Revenue will be one component used to determine target revenues that will replace the rate case-determined amounts (electric sales revenue, fuel, and purchased power components) and the RAM Revenue Adjustment amounts currently applied in the RBA Provision Tariff, with revenue taxes treated appropriately and consistently. EPRM, PIMs, SSMs, and other target revenue adjustments will continue to be applied according to existing methods in accordance with the RBA Provision tariff.

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[314]As noted in Section VI.E.1, supra, the Commission expects to review and address modifications to the Companies' existing RAM Provision tariff ahead of the March 31, 2021 RBA Review Transmittal filing to effectuate the transition from the RAM Provision tariffs to the pertinent PBR tariffs in 2021.

The Companies' February and March 2021 Annual RBA Review transmittals shall reflect this transition from utilizing the RAM Provision tariff to the new ARA implementing tariffs.

Thereafter, the review processes for the "new" and amended tariffs, including filing deadlines, review period, and accrual and effective dates, will take effect, as discussed in Section IV.E.3, infra.

3.

Annual Review Cycle

The Companies, the Consumer Advocate, and Ulupono all propose detailed processes for annual submittal, review and approval for revenue adjustments under the PBR Framework. In their proposals, both the Companies and the Consumer Advocate proposed processes to periodically review the PBR Framework and adjust the Companies' target revenues and RBA Rate Adjustment, as may be appropriate.[315] Both Parties have proposed a biannual review, which contemplates a filing in the fall to facilitate an adjustment to target revenues on January 1 of the following calendar year, followed by a subsequent review and potential adjustment the following spring.

[315]See Hawaiian Electric ISOP at 139-40; and Consumer Advocate ISOP at 129-31.

The primary differences between the Companies' and the Consumer Advocate's proposals appear to relate to the substance of their respective filings, the effective date of adjustments to target revenues, and whether the fall review and January 1 effective date will include updated RBA Rate Adjustments.

The Companies favor a more comprehensive revenue adjustment in the fall, with a September 30 filing that would update the ARA's target revenues (the Companies propose using the September Blue Chip Economic Indicators publication to determine GDPPI), as well as update the RBA Rate Adjustment to account for any known PIM rewards/penalties and any outstanding RBA balances as of August 1 and including any known EPRM adjustments.[316] This would result in changes to the Companies' target revenues and RBA Rate Adjustment the following January 1. This would be followed by a second filing on the next March 15, which would provide an update to the prior September 30 filing, reflecting: target revenues that have accrued since January 1, any approved Z-Factors, EPRM relief (since January 1), actual PIM and ESM results, and updated reconciliation of the RBA balance as of December 31.[317] This would result in a second set of adjustments to

[316]Hawaiian Electric RSOP, Exhibit D at 5.

[317]Hawaiian Electric RSOP, Exhibit D at 5.

effective target revenue and the RBA Rate Adjustment effective May 1.

The Consumer Advocate proposes a more abbreviated filing in the fall, due by December 1, which would reflect updated GDPPI projections. This would result in updated ARA target revenues that the Companies could begin accruing, but not collecting, as of January 1.[318] Thereafter, a more robust filing would occur on March 31 of the following year, which would include, among other things: revisions or corrections to the abbreviated December filing (including updates to GDPPI escalation, if necessary); reconciliation of revenue decoupling for the prior year; and adjustments for ESM and PIM results for the prior year; adjustments for any EPRM or Z-Factor costs recovery.[319] An RBA Rate Adjustment would take effect annually on August 1.[320]

In addition, the Consumer Advocate proposes a number of reporting requirements, including an annual review of the PBR Framework's Performance Mechanisms (PIMs, SSMs, Scorecards, and Reported Metrics),[321] which would be facilitated by quarterly

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[318]See Consumer Advocate RSOP at 187.

[319]Consumer Advocate RSOP at 187.

[320]See Consumer Advocate ISOP, Exhibit 1 at 2 ("Revenue Balancing Account Rate Adjustments are to be effective over the subsequent August 1st through July 31st period.").

[321]See Consumer Advocate RSOP at 182-83.

reports filed by the Companies "as soon as practicable after the conclusion of each quarter."[322] This annual report would "include the Companies' assessment of its performance relative to any established PIM and the savings achieved within any SSM with a calculation of the incentive it believes it has earned including all underlying data presented in a transparent format."[323] The Consumer Advocate submits that such a process will "enable modifications of PIMs/SSMs on an on-going basis if they do not serve their intended purpose or are not efficient or equitable."[324]

The Companies contend that the Consumer Advocate's proposal will negatively impact their cash flow, by delaying the effective date of the RBA Rate Adjustment to August 1, which, the Companies note, is actually later than the current effective date of June 1 under the "current" RAM/RBA decoupling framework.[325] Conversely, the Consumer Advocate maintains that "no harm to utility financial performance will occur from these review intervals because ARA increases would be accrued on the utilities' books effective January 1 of each year."[326]

[322]Consumer Advocate RSOP at 182.

[323]Consumer Advocate RSOP at 182.

[324]Consumer Advocate RSOP at 182.

[325]Hawaiian Electric RSOP at 40-41.

[326]Consumer Advocate RSOP at 191.

The Companies further argue that the Consumer Advocate's suggested reporting requirements will negatively impact administrative efficiency by increasing the complexity, frequency, and cost of the Companies' reporting requirements and submit that "[a]dministrative efficiencies gained from PBR and other cost control initiatives should not then be undone by increasing the amount of oversight and administrative regulatory costs in other areas, as the Consumer Advocate seems to suggest."[327] The Consumer Advocate states that such frequent reporting requirements will ensure that the PIMs and SSMs are working as intended and provide for timely correction if they are not.[328]

Upon review of the record and consideration of the arguments raised by the Parties, the Commission establishes the following annual review cycle provided in Table 13, below:

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[327]Hawaiian Electric RSOP at 32.

[328]See Consumer Advocate RSOP at 182-85.

Table 13: Annual Review Cycle	
NOTE: The Annual Filing Cycle for the MRP begins mid-year, such that the Companies' first biannual report for the following calendar year will be the Fall Revenue Report, which will determine the adjustments to target revenues and the RBA Rate Adjustment effective January 1 of the following year.	
October 31	Companies' Fall Revenue Report: preliminary report containing, at a minimum, the GDPPI projections from the October Blue Chip Economic Indicators, as well as any actual and known revenue adjustments (i.e., revenue adjustments that are ready for perfunctory implementation).
November 30	Consumer Advocate's Statement of Position on the Fall Revenue Report.
December	Commission order addressing Fall Revenue Report, including any adjustments to target revenues and RBA Rate Adjustment mechanism. Companies file tariffs consistent with Commission order, to take effect January 1 of following year.
January 1	Effective date of approved target revenue adjustments and RBA Rate Adjustments based on Commission order addressing prior year's Fall Revenue Report.
February 28	Companies file schedules and other supporting workpapers for all known attained PIMs and SSMs and EPRM revenue adjustments.

March 31	Companies' Spring Revenue Report: comprehensive report which will serve as the basis for addressing all PBR revenue factors, including ARA adjustments, updated GDPPI projections based on the March Blue Chip Economic Indicators, actual PIM performance, EPRM adjustments accrued as of March 31, any ESM adjustments, any approved Z-Factor costs, any approved pilot project costs, and any additional target revenue adjustments from the RBA. Companies' annual Pilot Update. Companies' annual PIM and SSM Performance Review: Companies' assessment of their performance relative to any established PIM, or savings achieved within any SSM, with a calculation of the incentive the Companies (or individual utility, depending on the circumstances) believe they have earned. • Supporting data shall be provided in a transparent format. • If any of the Companies seek a revenue adjustment for a PIM or SSM as part of the Fall Revenue Report, they shall file a Performance Review for the applicable PIM or SSM as part of that period's Fall Revenue Report. Companies file their annual RBA Review Transmittals.
April 30	Consumer Advocate's Statement of Position addressing the Spring Revenue Report and RBA Review Transmittals.
May	Commission order addressing Spring Revenue Report and RBA Review Transmittals, including any adjustments to target revenues and RBA Rate Adjustment mechanism. Companies file tariffs consistent with Commission order, to take effect June 1.

June 1	Effective date of approved target revenue adjustments and RBA Rate Adjustments based on Commission order addressing Spring Revenue Report and RBA Review Transmittals.
October 31	Cycle repeats itself for the remainder of the MRP, with Companies' submission of Fall Revenue Report, plus any PIM/SSM Performance Review for PIM/SSM rewards the Companies seek to recover as part of the Fall Revenue Report, if any, in accordance with approved PIM and SSM tariffs.[329]

In establishing the above schedule, the Commission has largely adopted the biannual review process proposed by the Companies and the Consumer Advocate. In setting the deadlines for the Fall Revenue Report submissions, the Commission has adopted the Companies' proposed dates, as they are earlier and will allow more time for the Consumer Advocate and Commission to review the Fall Revenue Report. While the Commission appreciates that the Consumer Advocate's proposed December submission dates may allow for more updated information, the Commission is concerned about the administrative strain on resources necessary to complete a sufficient review prior to January 1.

[329]Consistent with the June 1, 2021, effective date for the PBR Framework and the 5-year MRP, the "last" scheduled review of the initial MRP will occur in Spring of 2026. That being said, this schedule is subject to the results of the comprehensive review of the PBR Framework that will occur in the fourth year of the MRP, which may extend, modify, or replace the PBR Framework.

The deadlines for the Spring Revenue Report are largely based on the current RAM/RBA decoupling schedule, with submissions spread over February and March, Statement of Position by the Consumer Advocate in April, and Commission order in May, ahead of a June 1 effective date. As the Companies and Consumer Advocate are familiar with this schedule, the Commission believes it will help facilitate a smoother transition to the PBR Framework, as the Parties and Commission adjust to the new schedules and tariffs.

Consistent with the PBR principle of improving administrative efficiency,[330] this 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. As noted in Section IV.E.1, supra, the Commission has allocated time post-Phase 2 D&O for the Parties to collaborate on developing template schedules and forms to facilitate these reviews.

Additionally, the Commission has taken into account the Companies' requests to reduce lag and improve cash flow, and the

[330]See Phase 1 D&O at 21.

above schedule incorporates two annual opportunities for RBA Rate Adjustments. To the extent adjustments to target revenues are known and ready for implementation at the time of the Fall Revenue Report, they may be submitted for review and potential incorporation into the January RBA Rate Adjustment. However, the Commission cautions that only actual and known revenue adjustments, requiring perfunctory review, will be considered as part of the Fall Revenue Report review. Estimates or projections (with the exception of the Companies' GDPPI, based on Blue Chip Economic Indicators projections) will not be sufficient to justify an RBA Rate Adjustment for January 1.

Regarding the Consumer Advocate's request for quarterly and an annual performance report for Performance Mechanisms, the Commission finds that an annual report for PIMs and SSMs would be useful in evaluating the efficacy of the PBR Framework but, recognizing the Companies' concerns regarding time and resources, will adopt a modified version of the Consumer Advocate's proposed report.

The Companies shall file an annual performance review ("Performance Review") of all PIMs and SSMs in effect for the prior year, which will be submitted in March as part of the Companies' Spring Revenue Report. The Consumer Advocate may comment on the Performance Report as part of its Statement of Position addressing the Companies' Spring Revenue Report. The Performance Review shall include the Companies' assessment of its performance relative to any established PIM, or savings achieved within any SSM, with a calculation of the incentive the Companies (or individual utility, depending on the circumstances) believe they have earned. Supporting data shall be provided in a transparent format. If the Companies, or an individual utility, seek a revenue adjustment for a PIM or SSM as part of the Fall Revenue Report, the Companies shall file a Performance Review for the applicable PIM or SSM. Quarterly reports, as suggested by the Consumer Advocate,[331] will not be required.

This balances the need to timely receive and review data regarding PIM and SSM operation, so as to allow the Commission to determine whether the PIMs and SSMs are working as intended (and whether any adjustments are necessary), with the administrative burden of producing multiple reports per year. In essence, whenever the Companies seek to collect revenues they believe they have earned pursuant to a PIM or SSM, they will be required to provide a report which will serve the dual purposes of verifying their compliance with the PIM or SSM, as well as allowing the

[331]See Consumer Advocate ISOP at 123.

Commission to consider whether any modifications to the PIM or SSM are warranted.[332]

A table summarizing all of the reviews and processes following the issuance of this D&O is provided in Appendix C to this D&O.

4.

Rate Design

While this proceeding has focused on how the Companies' revenue requirements will be determined in the PBR Framework under the ARA and Performance Mechanism opportunities, there has been less attention devoted to discussing how customer rates will be designed and/or adjusted during the MRP. As the methods by which the Companies' revenue requirement evolve, rate design should also modernize to better reflect cost causation and the needs of the grid to send more accurate price signals to customers.[333]

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[332]C.f., "Hawaii PV Coalition, Hawaii Solar Energy Association and Distributed Energy Resource Council of Hawaii Post Hearing Brief; and Certificate of Service," filed October 19, 2020, at 2 (stating that DER-related PIMs adopted in this proceeding should be done on an "interim basis" so as to preserve flexibility to "ensure that the ensuing PIMs are based on the best available data and information to drive fundamental change and improvement in the utility relationship with [the DER community].").

[333]C.f., Hawaiian Electric ISOP at 133-34 ("Consideration of rate design revision becomes more urgent to the extent that the revenues recovered through annual revenue adjustment mechanisms

The Commission recognized this in the Phase 1 D&O, stating "[d]ue to the development of a MRP, as well as other revenue adjustment mechanisms . . . there will likely be a need to examine [revenue neutral] changes to the Companies' rate design structure during the MRP."[334] This issue has been raised by several of the Parties as well.[335]

In the Phase 1 D&O, the Commission expressed its inclination to address revenue neutral rate design changes in a separate proceeding.[336] The Commission continues to support this as an appropriate course of action and anticipates addressing rate design-related issues during the MRP in the Commission's DER investigation, Docket No. 2019-0323, but will consider opening a separate proceeding focused on rate design in the future, depending on the circumstances.

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during the [MRP] become a greater and more significant proportion of total Target Revenue recovery."); and Consumer Advocate ISOP at 90 ("The Consumer Advocate agrees that revenue neutral rate design changes will likely be needed in the absence of rate cases and to coordinate changes arising in the Advanced Rate Design Track of the Commissions' Distributed Energy Resource Policies Investigation in Docket No. 2019-0323.").

[334]Phase 1 D&O at 32.

[335]See Hawaiian Electric ISOP at 133-34; Consumer Advocate ISOP at 90; and Ulupono ISOP at 18.

[336]Phase 1 D&O at 32.

Any such adjustments would be revenue neutral, so as not to contradict the adjustments to revenues effectuated though the ARA and other PBR Framework mechanisms.

5.

End of MRP Review

Another issue that has been debated by the Parties is what should be done at the end of the MRP; in particular, whether a return, in part or full, to traditional COSR is appropriate to "rebase" the Companies' rates. The Companies, although stating that a return to a complete COSR rate case may not be necessary, maintain that they should have the right to seek a COSR rate case, depending on the circumstances.[337] In contrast, the other Parties are opposed to any return to a traditional COSR-based rate case and have proposed a variety of alternative review processes instead.[338]

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[337]See Hawaiian Electric RSOP at 191.

[338]See Consumer Advocate RSOP at 64-67 (opposing a return to COSR and proposing an "expedited earnings assessment for each utility"); Blue Planet RSOP at 18-22 (challenging the Companies' legal argument that they are "entitled" to a general rate case" on the basis of due process and contending that the Commission, alone, should have the discretion to decide how to proceed at the end of the MRP); and Ulupono RSOP at 27-30 (opposing a return to a COSR rate case and proposing Commission review only in the event of a credit downgrade or based on a "PBR Review score" is triggered).

Parties generally agree that there should be a pre-determined process to address the end of the MRP, but disagree over the scope, nature, and degree of details that should be provided up front.[339] Furthermore, several of the Parties contend that the existing safeguards in their comprehensive PBR proposals mitigate the concerns associated with uncertainty related to the end of the MRP.

Upon review of the record and consideration of the Parties' arguments, the Commission finds that the most appropriate course of action for this MRP is to affirm that there will be a review process during the fourth year of the MRP (i.e., a year before the MRP is scheduled to expire), during which the Commission will comprehensively evaluate the PBR Framework to determine the

[339]See Hawaiian Electric RSOP at 186 ("The Companies' position is that the process for determining whether base rates may be reset at the end of the initial control period should be established with some precision at the outset."); Consumer Advocate RSOP at 65-67 (describing an expedited earnings assessment held in the fourth year of the MRP to determine whether any changes to the PBR Framework are warranted and/or whether a "one-time 'update' to revenue requirements using an historical test year data" would be appropriate); Blue Planet ISOP at 18 (proposing a deliberately flexible review process, where the Commission reviews the PBR Framework prior to the end of the MRP and retains discretion to continue the PBR Framework, modify the Framework, return to COSR, or adopt an alternative regulatory approach); and Ulupono ISOP at 12-16 (describing a methodology which would determine when Commission review of the PBR Framework would be necessary, based on the Companies' ROE).

appropriate course of action.[340] The Commission agrees with the need for a process to address the end of the MRP, and believes this comprehensive review in Year 4 of the MRP balances this need with the importance of allowing the Companies to adapt to the incentives inherent in the PBR Framework. Further details as to the specific nature of this review will be provided by the Commission closer in time to Year 4 of the MRP. While the Commission retains the discretion to fashion a remedy that is the most appropriate under the circumstances, it makes clear that its preference is not to return to a COSR general rate case.

This is not a "wait and see" approach as the Companies contend,[341] as the Commission will not be passively sitting back and watching PBR unfold without taking action until the end of the MRP. On the contrary, the Commission will be actively monitoring the operation of the PBR Framework and considering the appropriate course of action based on its operation. Merely because the details of this comprehensive review will not be communicated to the Parties until the fourth year of the MRP does not mean that

[340]C.f., Blue Planet ISOP at 18 ("Given the impossibility of predicting the future in five years, and particularly during this first transitional step toward a larger MRP period, Blue Planet is not inclined to prescribe further detail for this process through engineered criteria or formulaic approaches.")

[341]See Hawaiian Electric RSOP at 189.

the Commission will wait until Year 4 to begin reviewing the PBR Framework and considering improvements.

The review process described above is deliberately designed to ensure that the incentives of the PBR Framework are not diluted by advance planning to address the end of MRP. At this time, the Commission believes that prescribing the end of the MRP too far in advance may inadvertently provoke gaming or the adoption of a "sit tight" approach that ultimately distracts from the true focus of changing operations to align with the PBR incentives.

Rather than worry about what will happen at the end of the MRP, the Companies should focus on how to thrive under the PBR Framework, regardless of the ultimate duration of the MRP. The expectation should not be that the PBR Framework is an experiment that will be abandoned in favor of a return to COSR at the first challenge - rather, the expectation is that the Commission will work with the Companies and stakeholders to modify the PBR Framework over time to support its continued longevity and success.

The PBR Framework approved in this D&O has been carefully designed to include multiple safeguards and review opportunities to protect the Companies' financial health from extreme hardship. As stated in the Phase 1 D&O, the utility's financial integrity is one of the guiding principles of the PBR Framework.[342] Indeed, given the robust network of protections, it would be surprising if major, persistent flaws in the PBR Framework were not brought to the Commission's attention until the end of the MRP. More likely, persistent negative effects on the Companies' financial health would be signaled much earlier through the operation of the ESM, the triggering of a Re-Opener, or during the annual review cycle.

The Commission emphasizes that the PBR Framework established herein represents a significant opportunity for the Companies, and the Commission is heavily invested in the success of the PBR Framework and intends monitor its implementation carefully to ensure that this transition, while perhaps reflecting some uncertainty, is fair and reasonable. Growing pains are expected, but the Commission will move swiftly to address any unintended consequences that may arise.

In sum, the Commission affirms that it will hold a formal review process to comprehensively review the PBR Framework in Year 4 of the MRP. The nature of that proceeding, as well as the potential resulting actions will be announced closer to that time by the Commission.

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[342] See Phase 1 D&O at 21 and 25-26.

V.

FINDINGS OF FACT AND CONCLUSION OF LAW

The Commission summarizes its findings and conclusions discussed above as follows:

1. The Commission establishes a new PBR Framework to govern the regulation of Hawaiian Electric.

2. The PBR Framework shall initially be implemented over a five-year MRP, but may be extended following a comprehensive review of the PBR Framework that will take place during the fourth year of the MRP.

3. During the MRP, Hawaiian Electric's authorized target revenues will be determined by an annual indexed-revenue formula, the ARA, based on the following formula:

ARA = (I-Factor) – (X-Factor) + (Z-Factor) – (Customer Dividend)

A. The I-Factor will be determined based on GDPPI, as set forth in Hawaiian Electric's Blue Chip Economic Indicators.

B. The X-Factor shall be set at 0%, based on the current application of the RAM/RBA decoupling structure, which provides for a similar "GDPPI plus 0% productivity escalator."

C. The Z-Factor will provide Hawaiian Electric with an *ex post* opportunity to review and recover reasonable and prudent costs expended to address exogenous events. Review and approval of any Z-Factor costs will be determined on a case-by-case basis.

D. The Customer Dividend shall be the sum of two components: (1) a 0.22% annual compounded factor; and (2) a $22.16 million subtractive amount representing the Savings Commitment arising from the HECO Rate Case Settlement, representing the efficiencies expected to be realized as a result of the Management Audit, determined on a cash basis and averaged over the 5-year MRP.

E. In calculating the ARA Adjustment, the I-Factor, X-Factor, and 0.22% annual multiplicative component of the CD shall be based on and summed to the compounded portion of ARA Revenue; the Savings Commitment component of the CD and the Z-Factor amounts shall be applied to the non-compounded portions of the ARA Revenue. The ARA Revenue Adjustment will include the compounded and the non-compound components of the ARA formula factors.

4. Hawaiian Electric may seek revenues in addition to those provided by the ARA for the recovery of approved costs and expenses through the EPRM adjustment mechanism. Review and approval of any eligible costs for EPRM relief will be on a

case-by-case basis, consistent with the EPRM Guidelines attached to this D&O.

A. The MPIR Guidelines are terminated as of the date of this D&O and immediately replaced with the EPRM Guidelines, attached as Appendix A to this D&O, with the exception that any pending application for MPIR relief submitted by the Companies prior to this D&O will be grandfathered under the MPIR Guidelines.

B. If the Companies wish for a pending MPIR application to be reviewed under the EPRM Guidelines, they must make an affirmative written request in the appropriate docket. This may require the Companies to file supplemental material, as may be required under the EPRM Guidelines.

5. Hawaiian Electric may also earn financial rewards and/or incur financial penalties based on a portfolio of PIMs and SSMs that will be in addition to annual revenues provided by the ARA.

A. The Commission approves the Interconnection Approval PIM, subject to resolution of final details in the Post-D&O Working Group, providing financial rewards and penalties based on the Companies' ability to improve the time necessary to complete those steps within the Companies' control to interconnect DER systems <100 kW in size.

B. The Commission approves the Grid Services PIM, providing a financial reward based on the Companies' ability to increase its acquisition of grid serves from DERs. This PIM shall be interim in nature, expiring at the end of 2022, and is intended to be replaced with a more sophisticated PIM that will incent utilization of grid services from DERs, to be developed in the DER proceeding, Docket No. 2019-0323.

C. The Commission approves the RPS-A PIM, as proposed by Ulupono, and as modified herein, providing a financial reward for accelerated achievement of the State RPS goals.

D. The Commission approves the LMI Energy Efficiency PIM, subject to resolution of final details in the Post-D&O Working Group, providing a financial reward to incent the Companies to collaborate with Hawaii Energy to deliver energy savings to LMI customers through energy efficiency measures resulting in load reduction.

E. The Commission approves the AMI Utilization PIM, subject to resolution of final details in the Post-D&O Working Group, incenting the acceleration of the number of customers with advanced meters enabled to support time-varying rates and next generation DER programs.

F. In addition, the Companies' existing PIMs, based on SAIDI, SAIFI, and Call Center performance will continue, offering additional revenue opportunities for the Companies.

G. Although not establishing a PIM at this time, the Commission will closely monitor the Companies' development and implementation of its online Energy Portal in the context of the Companies' Grid Modernization efforts in Docket No. 2018-0141.

6. In February of 2021, the Commission will convene a Post-D&O Working Group to finalize development of the Interconnection Approval PIM, LMI Energy Efficiency PIM, the AMI Utilization PIM, and an initial portfolio of Scorecards and Reported Metrics.

A. Thereafter, the Post-D&O Working Group will serve as a Party-led forum to continue discussing and developing Performance Mechanism proposals for future consideration.

7. Additional PIMs and SSMs to incent competitive procurement of renewable generation and NWAs may be proposed, solicited, and/or implemented during the MRP in other proceedings or as developed by the Post-D&O Working Group.

8. The Companies will develop a webpage to report the Companies' progress, as measured by the approved portfolio of Scorecards and Reported Metrics.

A. By June 30, 2021, the Companies shall have a draft webpage ready for review and approval by the Parties and Commission.

B. Following approval, this webpage should be updated throughout the MRP to timely reflect the Companies' performance, as well as to include any additions or modifications to Scorecards and/or Reported Metrics.

9. The RBA decoupling mechanism will continue to operate and determine Hawaiian Electric's allowed rates based on a biannual reconciliation of each of the Companies' respective target revenues and collected revenues.

A. The initial target revenues for the Companies shall be the current effective rates of each of the Companies at the time the approved PBR tariffs go into effect.

B. Target revenues may then be adjusted biannually, according to the annual review cycle, based on the reconciliation of the RBA, application of the ARA formula, adjustments for any approved EPRM revenues, any financial rewards or penalties related to PIMs and SSMs, any costs related to approved pilot projects, and/or any other adjustments otherwise approved by the Commission.

10. In addition to revenues recovered pursuant to the RBA, the Companies will continue to recover costs through their

various automatic cost recovery mechanisms (e.g., ECRC, PPAC, DSM, REIP, DRAC, and pension and OPEB tracker), which will continue as currently implemented.

11. The Commission also establishes a Pilot Process to oversee the expedited review of pilot projects vetted by the Companies, consistent with a Workplan submitted to the Commission, that will facilitate the implementation of pilots that test new technologies, customer engagement programs, business models, and other arrangements.

A. Following the development of a Workplan submitted to the Commission, the Companies may submit notice of intent to implement a pilot consistent with the Workplan. The Commission shall review and issue an order addressing such notice within forty-five (45) days of submission.

B. The Companies will file an annual Pilot Update report covering all active pilots by March 31 each year. In addition to providing an update on ongoing pilot programs, the Pilot Update may include final reporting on completed projects, as applicable.[343]

C. No Pilot Update will be required for 2021, as it is expected that no new pilots will yet be in place, given the

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[343] See EoT Pilot Framework at 11.

PBR tariff implementation details and Workplan process that must be accomplished first.

D. The Companies shall submit the annual costs and revenues (if any) associated with any implemented pilot project as part of the Pilot Update, which will be reviewed in the spring of each year as part of the Commission's review of the Companies' Spring Revenue Report. The Commission will determine, at that time, the appropriate amount of annual recoverable pilot costs.

E. The Pilot Process will incorporate an annual cap of $10 million.

F. The Companies shall develop a written Pilot Process consistent with this D&O for the Commission's review, which shall be submitted prior to the Companies' Pilot Process Workplan.

12. The PBR Framework will include an ESM as summarized above in Table 11, reproduced below:[344]

Table 11: ESM						
<5.00% 90/10 sharing	<6.50%-5.00% 50/50 sharing	<9.50%-6.50% No sharing	9.50%	>9.50%-12.50% No sharing	>12.50%-14.00% 50/50 sharing	>14.00% 90/10 sharing

[344]Sharing ratios reflect ratepayers/Companies.

A. Shared costs to the Companies shall be collected in the following year as part of the Spring Revenue Report, effective June 1.

B. Shared earnings to ratepayers shall be returned as a bill credit in the following year as part of the Spring Revenue Report, effective June 1.

C. The Commission finds that an ESM will help alleviate concerns by providing assurances that significant decreases in earnings will be mitigated; likewise, in the event incentive mechanisms are initially too generous, excess earnings by the Companies will be shared with their customers.

13. The PBR Framework will include a Re-Opener mechanism, under which the Commission may review particular PBR mechanism(s) during the MRP to determine if they are operating as intended.

A. The Companies may initiate a request for review based on the following triggering events: (i) the Companies' credit rating outlook indicates a potential credit rating downgrade below investment grade status, as determined by Moody's, Standard & Poor's, or Fitch credit rating agency; or (ii) the Companies' actual ROE enters the outermost sharing tiers of the ESM (either upside or downside).

B. The Commission may initiate a review of any PBR mechanism(s) at any time, on its own motion.

C. Based on its review, the Commission will exercise its discretion to fashion a remedy deemed appropriate under the circumstances, which may involve leaving the PBR mechanism(s) alone, modifying the mechanism(s), or terminating the mechanism(s) entirely.

14. The Commission will review the PBR Framework on an annual cycle according to the following schedule:

A. By October 30, the Companies shall file a Fall Revenue Report containing, at a minimum, the GDPPI projections from the October Blue Chips Economic Indicators, as well as any actual and known revenue adjustments that are ready for perfunctory implementation.

B. By November 30, the Consumer Advocate shall file its Statement of Position on the Companies' Fall Revenue Report.

C. In December, the Commission will issue an Order addressing the Companies' Fall Revenue Report, including any ARA adjustments, which will take effect the following January 1; the Companies shall file compliant tariffs, which the Commission shall approve prior to January 1.

D. On the following January 1, the RBA Rate Adjustment will be modified to incorporate the Commission's Order addressing the Companies' Fall Revenue Report.

E. By the following February 28, the Companies shall file schedules containing all known information about any attained PIMs and/or accrued EPRM revenues.

F. By March 31, the Companies shall file a Spring Revenue Report, which will serve as the basis for review of all PBR revenue factors, including ARA adjustments, actual PIM performance, EPRM adjustments accrued as of March 31, any ESM adjustments, any approved Z-Factor costs, and any additional target revenue adjustments from the RBA.

G. Also by March 31, the Companies shall file their annual Pilot Update.

H. By April 30, the Consumer Advocate shall file its Statement of Position addressing the Companies' Spring Revenue Report.

I. In May, the Commission will issue an Order addressing the Companies' Spring Revenue Report, which will take effect June 1; the Companies shall file compliant tariffs, which the Commission shall approve prior to June 1.

J. On June 1, the RBA Rate Adjustment will be modified to incorporate the Commission's Order addressing the Companies' Spring Revenue Report.

K. This process will then repeat itself, with the Companies filing their Fall Revenue Report by October 30.

L. The deadlines for the Spring Revenue Report are largely based on the current RAM/RBA decoupling schedule, which should facilitate a smoother transition to the PBR Framework, as the Parties and Commission adjust to the new schedules and tariffs.

M. The Commission has taken into account the Companies' requests to reduce lag and improve cash flow, and has incorporated two annual opportunities for RBA Rate Adjustments, to the extent adjustments to target revenues are known and ready for implementation at the time of the Fall and Spring Revenue Reports.

N. As part of their Spring Revenue Report, the Companies shall file an annual Performance Review of all PIMs and SSMs in effect for the prior year, which shall include the Companies' assessment of its performance relative to any established PIM or savings achieved with any SSM with a calculation of the incentive the Companies (or individual utility, depending on the circumstances) believe they have earned.

O. If an of the Companies seek a revenue adjustment for a PIM or SSM as part of the Fall Revenue Report, it shall file a Performance Review for the applicable PIM or SSM.

15. Any changes to the Companies' rate design during the MRP will be addressed in a revenue neutral fashion in the DER proceeding, Docket No. 2019-0323, or a separate proceeding, as determined by the Commission.

16. The Commission will hold a formal review process to comprehensively review the PBR Framework in Year 4 of the MRP. The nature of that proceeding, as well as the potential resulting actions will be announced closer to that time by the Commission.

A. While the Commission retains the discretion to determine the remedy it finds to be the most appropriate under the circumstances, its preference is not to return to a COSR general rate case.

17. Tariffs to implement the PBR Framework shall be developed according to the following schedule:

A. During January of 2021, the Parties will convene in a working group to develop and vet tariff language.

B. On February 15, 2021, Hawaiian Electric will submit draft tariffs for the Commission's review.

C. On March 8, 2021, the other Parties may submit comments on the draft tariffs.

D. The Commission will issue an order addressing the draft tariffs no later than April 1, 2021.

E. Hawaiian Electric will submit final tariffs to consistent with the Commission's order by April 30, 2021, with an expected effective date of June 1, 2021.

F. This schedule is subject to modification at the Commission's discretion; however, the Commission does not anticipate any significant changes.

18. A table summarizing all of the reviews and processes following the issuance of this D&O is provided in Appendix C to this D&O

VI.

ORDERS

THE COMMISSION ORDERS:

1. The PBR Framework to govern Hawaiian Electric is established, as set forth above.

2. The Parties shall collaborate to develop the tariffs necessary to implement the PBR Framework, as set forth above in Table 12.

3. The Post-D&O Working Group process will commence as set forth above in Table 10.

4. The Companies shall submit a written Pilot Process for the Commission's review and approval, consistent with this D&O.

5. The MPIR Guidelines are terminated as of the date of this D&O and immediately replaced with the EPRM Guidelines, attached as Appendix A to this D&O, with the exception that any pending application for MPIR relief submitted by the Companies prior to this D&O will be grandfathered under the MPIR Guidelines. If the Companies wish for a pending MPIR application to be reviewed under the EPRM Guidelines, they must make an affirmative written request in the appropriate docket.

DONE at Honolulu, Hawaii DECEMBER 23, 2020.

PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

By James P. Griffin
James P. Griffin, Chair

By Jennifer M. Potter
Jennifer M. Potter, Commissioner

APPROVED AS TO FORM:

By
Leodoloff R. Asuncion, Jr., Commissioner

Mark Kaetsu
Mark Kaetsu
Commission Counsel

2018-0088.ljk

EXCEPTIONAL PROJECT RECOVERY MECHANISM ("EPRM") GUIDELINES

I. DEFINITIONS

As used in these Guidelines, unless the context clearly requires otherwise:

"Annual Revenue Adjustment" or "ARA" means the mechanism to provide annual revenue adjustments during a Multi-Year Rate Plan based on an index-driven formula.

"Commission" means the Public Utilities Commission of the State of Hawaii.

"Complex Projects" are projects that materially affect numerous aspects of the utility's operations, costs and/or earnings.

"Costs" means, inclusively, costs associated with return on and recovery of capital investments and/or expenses.

"Deferred Cost Project" means a project consisting of deferred expenses in excess of $2.5 million, subject to the Commission's review and approval of deferred accounting treatment.

"Electric utility" or "utility" means a provider of electric utility service that is regulated by and subject to the Commission's jurisdiction pursuant to Chapter 269, HRS.

"Eligible Projects" are approved Major Projects, Deferred Cost Projects, or O&M Projects eligible for revenue recovery through the EPRM adjustment mechanism as provided in these Guidelines.

"EPRM adjustment" means an adjustment to the utility's target revenues effectuated through the utility's Revenue Balancing Account tariff, determined in accordance with these Guidelines.

"EPRM adjustment mechanism" means the provisions of recovery of Eligible Projects provided for in these Guidelines.

"Guidelines" or "EPRM Guidelines" means this document and related effective provisions, as set forth in the Commission's implementing orders in Docket No. 2018-0088.

"Hawaiian Electric" or "HECO" means Hawaiian Electric Company, Inc.

"HECO Companies" or "Hawaiian Electric Companies" or "Companies" means Hawaiian Electric, Maui Electric, and Hawai'i Electric Light, collectively.

"HRS" means the Hawaii Revised Statutes.

"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.

"Maui Electric" or "MECO" means Maui Electric Company, Limited.

"Multi-Year Rate Period" or "MRP" means the multiple year period during which utility revenues are determined and controlled by an index-driven revenue formula, i.e., the Annual Revenue Adjustment.

"O&M Project" means a project or program consisting of incremental O&M expenses in excess of $2.5 million accumulated over a period of three consecutive years and otherwise not eligible for EPRM recovery as a Major Project or Deferred Cost Project. "Incremental" means in excess of O&M expenses already recovered in rates.

"PIM" means Performance Incentive Mechanism.

"REIP" means the Renewable Energy Infrastructure Program.

"RBA" means the Revenue Balancing account provisions established by the utility's Revenue Balancing Account tariff.

"RPS" or "Renewable Portfolio Standard" is defined as set forth in HRS § 269-91, as amended.

"SSM" means Shared Savings Mechanism.

"Utility System" means the electric system owned and operated by a utility (including any non-utility owned facilities that are interconnected to the system) consisting of power plants, transmission and distribution lines, and related equipment for the production and delivery of electric power to the public.

II. EPRM ADJUSTMENT MECHANISM

A. PURPOSE AND SCOPE OF THE EPRM ADJUSTMENT MECHANISM

1. Purpose and Scope. To provide a mechanism for recovery of revenues for net costs of approved Eligible Projects placed in service during a MRP, that is not provided for by other effective tariffs, the ARA, PIMs, or SSMs.

B. COST RECOVERY

1. Recovery of revenues for Major Project costs. Recovery of revenues through the EPRM adjustment mechanism may be found to be reasonable and explicitly allowed by order of the Commission, on a case by case basis, in the review of Major Projects in accordance with the applicable provisions of General Order No. 7.

2. Recovery of revenues for Deferred Cost Project and O&M Project costs. Recovery of revenues through the EPRM adjustment mechanism may be found to be reasonable and explicitly allowed by order of the Commission, on a case by case basis, in the review of any applications for Deferred Cost Projects or O&M Projects.

3. Prohibition of duplicative cost recovery. Notwithstanding any other specific provisions in these Guidelines, the EPRM adjustment mechanism shall not collect or recover revenues for costs or expenses recovered through other effective tariffs or revenue recovery mechanisms, including but not limited to revenues collected through the ARA, PIMs, or SSMs. The utility shall have the burden of proof in an application for recovery of revenues through the EPRM adjustment mechanism that recovered revenues shall not be duplicative.

4. Except as otherwise provided in these Guidelines, an electric utility shall be able to seek, through the ratemaking process or

other effective mechanisms (i.e., base rates, the ARA, or the REIP Surcharge), recovery of the reasonable and approved capital costs and expenses of Eligible Projects.

III. EPRM ADJUSTMENT MECHANISM PROVISIONS

A. DESCRIPTION OF THE EPRM ADJUSTMENT MECHANISM

1. The EPRM adjustment mechanism is a reconciled cost recovery mechanism to provide opportunity for reasonable recovery of specifically allowed revenues for the net costs of approved Eligible Projects placed in service during a MRP wherein cost recovery is not already provided for by other effective recovery mechanisms, including the ARA, PIMs, or SSMs.

B. ELIGIBLE PROJECTS

1. Projects and costs that may be eligible for recovery through the EPRM adjustment mechanism are Eligible Projects including but not restricted to the following illustrative examples, subject to the Commission's approval in accordance with these Guidelines:

   a. Infrastructure that is necessary to connect renewable energy projects. Infrastructure projects such as transmission lines, interconnection equipment and substations, which are necessary to bring renewable energy to the system. For example, renewable energy projects, such as wind farms, solar farms, biomass plants and hydroelectric plants, not located in proximity to the electric grid must overcome the additional economic barrier of constructing transmission lines, a switching station and other interconnection equipment. Building infrastructure to these projects will encourage additional renewable generation on the grid;

b. Projects that make it possible to accept more renewable energy. Projects that can assist in the integration of more renewable energy onto the electrical grid. For example, new firm generation or modifications to firm generation to accept more variable renewable generation or energy storage and pumped hydroelectric storage facilities that allow a utility to accept and accommodate more as-available renewable energy;

c. Projects that encourage clean energy choices and/or customer control to shift or conserve their energy use. Projects that can encourage renewable choices, facilitate conservation and efficient energy use, and/or otherwise allow customers to control their own energy use. For example, smart meters would allow customers to monitor their own consumption and use of electricity and allow for future time-based pricing programs. Systems such as automated appliance switching would provide an incentive to customers to allow a utility to mitigate sudden declines in power production inherent in as-available energy;

d. Approved or Accepted Plans, Initiatives, and Programs. Capital investment projects and programs, including those transformational projects identified within the Companies' ongoing planning and investigative dockets, as such plans may be approved, modified, or accepted by the Commission, and projects consistent with objectives established in investigative dockets;

e. Utility Scale Generation and Energy Storage. Electric utilities may seek recovery through the EPRM adjustment mechanism for the costs of a utility scale renewable generation or energy storage project, or a generation or energy storage project, that can assist in the integration of more renewable energy onto the electrical grid;

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

g. Service contracts. Company contracts with third-parties that (1) provide facilities or functionality that could otherwise be provided by a utility capital project and (2) provide services that directly and predominantly support another express EPRM Eligible Projects category.

2. Revenues eligible for EPRM relief are limited to those demonstrated to be : (i) be prudent and reasonable, (ii) provide customer value, (iii) enhance the affordability of energy services, and (iv) which are not directly or indirectly included in otherwise effective utility target revenues or other effective means of revenue recovery.

C. COST RECOVERY, EPRM ADJUSTMENT MECHANISM ELEMENTS, APPLICATIONS AND IMPLEMENTATION

1. Prior Commission approval shall be received for the costs of Eligible Projects to be recovered through the EPRM adjustment mechanism.

2. Elements of the EPRM adjustment mechanism.

a. Electric utilities may seek to recover Eligible Project costs, as described in 2(b), through the EPRM adjustment mechanism pursuant to the process set forth in section 3, below.

b. Costs eligible for the EPRM adjustment mechanism include:

i. Return on the net of tax average annual undepreciated investment or unamortized balance of the deferred cost in allowed

Major Projects or Deferred Cost Projects during EPRM recovery for each project at rate of return to be determined in the review of each Eligible Project application, as approved by the commission, except that in the initial year in service, the average of the balance at the in-service date and the balance at the end of the initial year;

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

iii. Amortization accruals (at a rate and methodology to be determined in review of each project's application, and as approved by the Commission) in allowed Deferred Cost Projects to begin on the date of the onset of EPRM recovery of the deferred cost for the project;

iv. Operations and maintenance expenses associated with the Eligible Project, not otherwise included in base rates, the ARA, or other cost recovery mechanisms;

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

c. All costs that are allowed to be recovered through the EPRM adjustment mechanism, shall be offset by any related net benefits of implementation of the approved Eligible Project (e.g., cost savings, revenue enhancements offset by O&M expenses, avoided depreciation on retired utility plant, etc.), as those net benefits are quantifiable and can be realized by the electric utility.

d. Project details, including the period of recovery of the project's cost, appropriate depreciation amounts and other project details, will be described within the business case included with the application for approval for recovery of costs through the EPRM adjustment mechanism.

e. Prior Commission approval shall be received in order for the costs of Eligible Projects to be included for cost recovery through the EPRM adjustment mechanism. Authorization to include recovery of costs for any specific project through the EPRM adjustment mechanism will ordinarily be granted or denied at the time the Commission issues a decision and order with respect to the proposed commitment of expenditures for the project in accordance with the applicable provisions of the Commission's General Order No. 7, or with respect to the proposed use of deferred accounting treatment for a project, or with respect to the authorization to recover expenses for a project. All costs proposed to be recovered through the EPRM adjustment mechanism will be limited to amounts approved in advance by the Commission.

f. Any approval of recovery of costs of an Eligible Project through the EPRM adjustment mechanism shall continue until new rates become effective that provide cost recovery for the Eligible Project or as otherwise provided by the Commission.

g. Recovery of incurred Eligible Project costs that exceed the amounts approved through the EPRM adjustment mechanism may be requested and considered for inclusion in the revenue requirements in subsequent proceedings, subject to review and approval by the Commission.

3. Applications for recovery through the EPRM adjustment mechanism.

a. With respect to applications seeking approval to utilize the EPRM adjustment mechanism for cost recovery, the electric utility bears the burden of proof that all project costs proposed for EPRM treatment meet the criteria specified herein and are not routine replacements of existing equipment or systems with like kind assets, relocations of existing facilities, restorations of existing facilities, or other kinds of business-as-usual investments.

b. Application for recovery of costs through the EPRM adjustment mechanism shall be made in conjunction with and as part of an application (1) pursuant to General Order No. 7, (2) for deferred accounting treatment, or (3) for other specific project or program authorization or approval. Absent a requirement to file an application for such project or program authorization or approval, the utility may file a separate independent application for recovery of costs through the EPRM adjustment mechanism.

c. Costs recovered through the EPRM adjustment mechanism shall be offset by all known and measurable operational net savings or benefits resulting from the Eligible Projects, (including accumulated depreciation and accumulated deferred income tax reserves, reductions in operating and maintenance expenses, related additional revenues, etc.) to the extent such savings or benefits are not passed on to ratepayers through energy cost or other adjustment clause mechanisms, and to the extent that such savings or benefits can reasonably be quantified. Net savings and benefits shall be offset as they are realized to the extent feasible. A business case study shall be submitted with each application identifying and quantifying all operational and financial impacts of the Eligible Project and illustrating the cost/benefit tradeoffs that justify proceeding with the project to the extent that such impacts can reasonably be determined.

d. Applications for Eligible Projects hereunder shall be made pursuant to General Order No. 7 procedures, or other applicable authority or procedure. Applications shall explain each basis for claimed EPRM eligibility, indicating the linkage of the project to any previously submitted planning studies, previously submitted construction budgets and any relevant active Commission dockets. Applications shall also include the information set forth in the following paragraphs (e) through (i).

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

f. A detailed schedule and budget for each element of the planned investment and activities shall be submitted, quantifying any contingencies, risks, and uncertainties, and indicating planned accounting and ratemaking procedures and expected net customer impacts.

g. Applications must state the specific criteria that are proposed for determination of used and useful status of the project, to ensure that no costs are deferred or recovered for new assets that are merely commercially available, but are not being used to provide service to ratepayers.

h. Recoverable costs shall be limited to the lesser of actual net incurred project/program costs or Commission-approved amounts, net of savings.

i. Complex Projects may be eligible for recovery through the EPRM adjustment mechanism, when supported by sufficient detailed business case analysis and documentation of reasonably quantifiable expected impacts, costs and benefits resulting from such projects.

j. Parties to the proceedings on applications for recovery of costs through the EPRM adjustment mechanism shall endeavor to complete procedural steps to allow for approval of the application within seven months of the date of application. The Companies acknowledge that the procedural schedule for EPRM for complex projects may take longer than projects that do not affect numerous aspects of the utility's operations, expenses, or earnings.

4. Implementation of EPRM adjustments.

a. The existence of these EPRM provisions does not constitute any assurance of ultimate entitlement to:

i. Approval for the commitment of funds for any specific project,

ii. Approval to include the costs for any specific project through the EPRM adjustment mechanism, or

iii. Approval to begin cost recovery (i.e., depreciation or amortization) or accelerate cost recovery for any specific project using the EPRM adjustment mechanism.

b. EPRM adjustments approved by the Commission in accordance with these Guidelines shall be implemented as an adjustment to the utility's target revenues implemented in accordance with the utility's RBA tariff.

c. Recovery of approved costs for Eligible Projects shall be included in the EPRM adjustment in accordance with a Commission order specifying the allowed recovery amount and period.

d. Collection and reconciliation of approved costs recovered through EPRM adjustments shall be implemented through the utility's RBA Rate Adjustment and RBA tariff provisions. The accrual, collection and reconciliation of revenues through the EPRM adjustment mechanism for each Eligible Project shall be documented and reviewed in the filing and review of the utility's RBA transmittals, as provided in the utility's RBA tariff.

e. Accrual of revenues recovered through the EPRM adjustment mechanism for an Eligible Project shall commence upon certification of the project's completion and/or in-service date in accordance with terms approved by the Commission at the time cost recovery through the EPRM adjustment mechanism is approved in the underlying proceeding for EPRM relief.

f. The accrual of revenues approved for recovery through the EPRM adjustment mechanism shall terminate (i) when and to the extent that the recovery of net costs is incorporated in base rates in a separate Commission proceeding, or (ii) when and to the extent that recovery of net costs is affected by other cost recovery means, or (iii) at a time, or according to, criteria specified by the Commission at the time recovery through the EPRM adjustment mechanism is approved.

g. Any over-recoveries or under-recoveries of revenues under the EPRM adjustment mechanism shall be refunded for collected, with interest, in accordance with the reconciliation provisions in subpart (c) above.

h. MECO may propose a mechanism or methods to provide separate recovery of Eligible Project costs for its Maui, Molokai, and Lanai divisions, otherwise consistent with these Guidelines.

~~MAJOR~~EXCEPTIONAL PROJECT ~~INTERIM~~ RECOVERY ~~("MPIR~~MECHANISM ("EPRM") GUIDELINES

~~1.~~I. DEFINITIONS

As used in these Guidelines, unless the context clearly requires otherwise:

"Annual Revenue Adjustment" or "ARA" means the mechanism to provide annual revenue adjustments during a Multi-Year Rate Plan based on an index-driven formula.

"Commission" means the Public Utilities Commission of the State of Hawaii.

"Complex ~~projects~~Projects" are projects that materially affect numerous aspects of the utility's operations, costs and/or earnings.

"Costs" means, inclusively, costs associated with return on and recovery of capital investments and/or expenses.

"Deferred Cost Project" means a project consisting of deferred expenses in excess of $2.5 million, subject to the Commission's review and approval of deferred accounting treatment.

"Electric utility" or "utility" means a provider of electric utility service that is regulated by and subject to the Commission's jurisdiction pursuant to Chapter 269, HRS.

"Eligible Projects" are approved ~~major projects~~Major Projects, Deferred Cost Projects, or O&M Projects eligible for revenue recovery through the ~~MPIR~~EPRM adjustment mechanism as provided in these Guidelines.

~~"Guidelines" or "MPIR~~"EPRM adjustment" means an adjustment to the utility's target revenues effectuated through the utility's Revenue Balancing Account tariff, determined in accordance with these Guidelines.

"EPRM adjustment mechanism" means the provisions of recovery of Eligible Projects provided for in these Guidelines.

"Guidelines" or "EPRM Guidelines" means this document and related effective provisions, as set forth in the Commission's implementing orders in Docket ~~NO. 2013-0141~~No. 2018-0088.

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"Hawaiian Electric" or "HECO" means Hawaiian Electric Company, Inc.

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"HECO Companies" or "Hawaiian Electric Companies" or "Companies" means Hawaiian Electric, Maui Electric, and Hawai'i Electric Light, collectively.

~~"Hawai'i Electric Light" or "HELCO" means Hawaii Electric Light Company, Inc.~~

"HRS" means the Hawaii Revised Statutes.

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"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.

~~"MPIR adjustment" means an adjustment to the utility's target revenues effectuated through the utility's Revenue Balancing Account tariff, determined in accordance with these Guidelines.~~

~~"MPIR adjustment mechanism" means the provisions of interim recovery of major projects provided for in these guidelines.~~

"Maui Electric" or "MECO" means Maui Electric Company, Limited.

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"Multi-Year Rate Period" or "MRP" means the multiple year period during which utility revenues are determined and controlled by an index-driven revenue formula, i.e., the Annual Revenue Adjustment.

"O&M Project" means a project or program consisting of incremental O&M expenses in excess of $2.5 million accumulated over a period of three consecutive years and otherwise not eligible for MPIR recovery as a Major Project or Deferred Cost Project. "Incremental" means in excess of O&M expenses already recovered in rates.

"PIM" means Performance Incentive Mechanism.

"REIP" means the Renewable Energy Infrastructure Program.

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"RBA" means the Revenue Balancing account provisions established by the utility's Revenue Balancing Account tariff.

"RPS" or "Renewable Portfolio Standard" is defined as set forth in HRS § 269-91, as amended.

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"SSM" means Shared Savings Mechanism.

"Utility System" means the electric system owned and operated by a utility (including any non-utility owned facilities that are interconnected to the system) consisting of power plants, transmission and distribution lines, and related equipment for the production and delivery of electric power to the public.

~~MPIR~~

~~2.~~II. EPRM ADJUSTMENT MECHANISM

~~a.~~A. PURPOSE AND SCOPE OF THE ~~MPIR~~EPRM ADJUSTMENT MECHANISM

~~i.~~1. Purpose and Scope. To provide a mechanism for recovery of revenues for net costs of approved Eligible Projects placed in service ~~between general rate cases~~during a MRP, that is not provided for by other effective tariffs, the ARA, PIMs, or SSMs.

~~b.~~B. COST RECOVERY

~~i.~~1. Recovery of revenues for Major Project costs. Recovery of revenues through the ~~MPIR~~EPRM adjustment mechanism ~~shall~~may be found to be reasonable and explicitly allowed by order of the Commission, on a case by case basis, in the review of Major Projects in accordance with the applicable provisions of General Order No. 7.

2. Recovery of revenues for Deferred Cost Project and O&M Project costs. Recovery of revenues through the EPRM adjustment mechanism may be found to be reasonable and explicitly allowed by order of the Commission, on a case by case basis, in the review of any applications for Deferred Cost Projects or O&M Projects.

~~ii.~~3. Prohibition of duplicative cost recovery. Notwithstanding any other specific provisions in these Guidelines, the ~~MPIR~~EPRM adjustment mechanism shall not collect or recover revenues for costs or expenses recovered

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~~iii.~~4. Except as otherwise provided in these Guidelines, an electric utility shall be able to seek, through the ratemaking process or other effective mechanisms (i.e., base rates, ~~Revenue Adjustment Mechanism~~the ARA, or the REIP Surcharge), recovery of the reasonable and approved capital costs and expenses of Eligible Projects.

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~~3.~~III. ~~MPIR~~EPRM ADJUSTMENT MECHANISM PROVISIONS

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~~a.~~A. DESCRIPTION OF THE ~~MPIR~~EPRM ADJUSTMENT MECHANISM

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~~i.~~1. The ~~MPIR~~EPRM adjustment mechanism is a reconciled cost recovery mechanism to provide opportunity for reasonable recovery of specifically allowed revenues for the net costs of approved Eligible Projects placed in service ~~between general rate cases under circumstances~~during a MRP wherein cost recovery is ~~limited by a revenue cap and is not~~not already provided for by other effective recovery mechanisms, including the ARA, PIMs, or SSMs.

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~~b.~~B. ELIGIBLE PROJECTS

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~~i.~~1. Projects and costs that may be eligible for recovery through the ~~MPIR~~EPRM adjustment mechanism are ~~Major~~Eligible Projects ~~subject to review and approval in accordance with the applicable provisions of the General Order No. 7,~~ including but not restricted to the following illustrative examples, subject to

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~~1.~~a. Infrastructure that is necessary to connect renewable energy projects. Infrastructure projects such as transmission lines, interconnection equipment and substations, which are necessary to bring renewable energy to the system. For example, renewable energy projects, such as wind farms, solar farms, biomass plants and hydroelectric plants, not located in proximity to the electric grid must overcome the additional economic barrier of constructing transmission lines, a switching station and other interconnection equipment. Building infrastructure to these projects will encourage additional renewable generation on the grid;

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~~2.~~b. Projects that make it possible to accept more renewable energy. Projects that can assist in the integration of more renewable energy onto the electrical grid. For example, new firm generation or modifications to firm generation to accept more variable renewable generation or energy storage and pumped hydroelectric storage facilities that allow a utility to accept and accommodate more as-available renewable energy;

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~~3.~~c. Projects that encourage clean energy choices and/or customer control to shift or conserve their energy use. Projects that can encourage renewable choices, facilitate conservation and efficient energy use, and/or otherwise allow customers to control their own energy use. For example, smart meters would allow customers to monitor their own consumption and use of electricity and allow for future time-based pricing programs. Systems such as automated appliance switching would provide an incentive to customers to allow a utility to mitigate sudden declines in

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power production inherent in as-available energy;

~~4.~~d. Approved or Accepted Plans, Initiatives, and Programs. Capital investment projects and programs, including those transformational projects identified within the Companies' ongoing planning and investigative dockets, as such plans may be approved, modified, or accepted by the Commission, and projects consistent with objectives established in investigative dockets;

~~5.~~e. Utility Scale Generation~~.~~ and Energy Storage. Electric utilities may seek recovery ~~of the costs~~ through the ~~MPIR~~EPRM adjustment mechanism for the costs of a utility scale ~~generation that is~~ renewable generation or ~~a generation~~energy storage project, or a generation or energy storage project, that can assist in the integration of more renewable energy onto the electrical grid;

~~6.~~f. Grid Modernization projects. Projects such as smart meters, inverters, energy storage, and distribution automation to enable demand response.

g. ~~Eligibility for recovery of revenues through the MPIR adjustment mechanism is restricted to revenues for projects that HECO, MECO, or HELCO demonstrate to~~Service contracts. Company contracts with third-parties that (1) provide facilities or functionality that could otherwise be provided by a utility capital project and (2) provide services that directly and predominantly support another express EPRM Eligible Projects category.

~~ii.~~2. Revenues eligible for EPRM relief are limited to those demonstrated to be : (i) be prudent and reasonable, (ii) provide customer value, (iii) enhance the affordability of energy

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~~c.~~C. COST RECOVERY, ~~MPIR~~EPRM ADJUSTMENT MECHANISM ELEMENTS, APPLICATIONS AND IMPLEMENTATION

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~~i.~~1. Prior Commission approval shall be received for the costs of Eligible Projects to be recovered through the ~~MPIR~~EPRM adjustment mechanism.

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~~ii.~~2. Elements of the ~~MPIR~~EPRM adjustment mechanism.

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~~1.~~a. Electric utilities may seek to recover Eligible Project costs, as described in 2(b~~)~~), through the ~~MPIR~~EPRM adjustment mechanism pursuant to the process set forth in section 3, below.

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~~2.~~b. Costs eligible for the ~~MPIR~~EPRM adjustment mechanism include:

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~~a.~~i. Return on the net of tax average annual undepreciated investment or unamortized balance of the deferred cost in allowed ~~Eligible~~Major Projects or Deferred Cost Projects during ~~MPIR~~EPRM recovery for each project at rate of return to be determined in the review of each Eligible Project application, as approved by the commission, except that in the initial year in service, the average of the balance at the in-service date and the balance at the end of the initial year;

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

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iii. Amortization accruals (at a rate and methodology to be determined in review of each project’s application, and as approved by the Commission) in allowed Deferred Cost Projects to begin on the date of the onset of EPRM recovery of the deferred cost for the project;

iv. Operations and maintenance expenses associated with the Eligible Project, not otherwise included in base rates, the ARA, or other cost recovery mechanisms;

~~e.~~v. Other relevant costs, applicable taxes, and/or offsetting cost savings, approved by the Commission.

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~~3.~~c. All costs that are allowed to be recovered through the ~~MPIR~~EPRM adjustment mechanism, shall be offset by any related net benefits of implementation of the approved Eligible Project (e.g., cost savings, revenue enhancements offset by O&M expenses, avoided depreciation on retired utility plant, etc.), as those net benefits are quantifiable and can be realized by the electric utility.

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~~4.~~d. Project details, including the period of recovery of the ~~Project’s~~project’s cost, appropriate depreciation amounts and other ~~Project~~project details, will be described within the business case included with the application for approval for recovery of costs through the MPIR adjustment mechanism.

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~~5.~~e. Prior Commission approval shall be received in order for the costs of Eligible Projects to be included for cost recovery through the ~~MPIR~~EPRM adjustment mechanism. Authorization to include recovery of costs for any specific project through the ~~MPIR~~EPRM adjustment mechanism will ordinarily be granted or denied at the time the Commission

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issues a decision and order with respect to the proposed commitment of expenditures for the project in accordance with the applicable provisions of the Commission's General Order No. 7~~.~~, or with respect to the proposed use of deferred accounting treatment for a project, or with respect to the authorization to recover expenses for a project. All costs proposed to be recovered through the ~~MPIR~~EPRM adjustment mechanism will be limited to amounts approved in advance by the Commission.

~~6.~~f. Any approval of recovery of ~~revenues~~costs of an Eligible Project through the ~~MPIR~~EPRM adjustment mechanism ~~pertains to (i) the period of~~shall continue until new rates become effective that provide cost recovery ~~up until review of the recovery of revenues~~ for the Eligible Project ~~in the utility's next following general rate case and until new effective~~ or ~~interim rates become effective~~ as ~~part of the utility's next following rate case, or (ii) a period~~ otherwise ~~specified~~provided by the Commission ~~at the time MPIR recovery is approved~~.

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~~7.~~g. Recovery of incurred Eligible Project costs that exceed the amounts approved through the ~~MPIR~~EPRM adjustment mechanism may be requested and considered for inclusion in the revenue requirements in subsequent ~~rate cases~~proceedings, subject to review and approval by the Commission.

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~~iii.~~3. Applications for ~~Recovery~~recovery through the ~~MPIR~~EPRM adjustment mechanism.

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~~1.~~a. With respect to applications seeking approval to utilize the ~~MPIR~~EPRM adjustment mechanism for cost recovery, the electric utility bears the burden of proof that all project costs proposed for ~~MPIR~~EPRM treatment meet the criteria specified herein and are not routine replacements of existing equipment or

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~~2.~~b. Application for recovery of ~~revenues~~costs through the ~~MPIR~~EPRM adjustment mechanism shall be made in conjunction with and as part of an application (1) pursuant to General Order No. ~~7~~7, (2) for deferred accounting treatment, or (3) for other specific project or program authorization or approval. Absent a requirement to file an application for such project or program authorization or approval, the utility may file a separate independent application for recovery of costs through the EPRM adjustment mechanism.

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~~3.~~c. Costs recovered through the ~~MPIR~~EPRM adjustment mechanism shall be offset by all known and measurable operational net savings or benefits resulting from the Eligible Projects, (including accumulated depreciation and accumulated deferred income tax reserves, reductions in operating and maintenance expenses, related additional revenues, etc.) to the extent such savings or benefits are not passed on to ratepayers through energy cost or other adjustment clause mechanisms, and to the extent that such savings or benefits can reasonably be quantified. Net savings and benefits shall be offset as they are realized to the extent feasible. A business case study shall be submitted with each application identifying and quantifying all operational and financial impacts of the Eligible Project and illustrating the cost/benefit tradeoffs that justify proceeding with the project to the extent that such impacts can reasonably be determined.

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~~4.~~d. ~~Application~~Applications for Eligible Projects hereunder shall be made~~,~~ pursuant to

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General Order No. 7 procedures~~. Smaller qualifying capital projects that are similar in nature,~~ or ~~directly related in purpose may be combined~~other applicable authority or ~~grouped into programs for review in accordance with General Order No. 7 procedures.~~procedure. Applications shall explain each basis for claimed ~~MPIR~~EPRM eligibility, indicating the linkage of the project to any previously submitted planning studies, previously submitted construction budgets and any relevant active Commission dockets. Applications shall also include the information set forth in the following paragraphs (e) through (i).

~~5.~~e. A detailed business case study shall be included, covering all aspects of the planned investments and activities, indicating all expected costs, benefits, scheduling and all reasonably anticipated operational impacts. The business case shall reasonably document and quantify the cost/benefit characteristics of the investments and activities, indicating each criterion used to evaluate and justify the project, including consideration of expected risks and ratepayer impacts. The business case should also clearly outline how it will advance transformational efforts with appropriate quantifications, to the extent such quantifications can reasonably be determined.

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~~6.~~f. A detailed schedule and budget for each element of the planned investment and activities shall be submitted, quantifying any contingencies, risks, and uncertainties, and indicating planned accounting and ratemaking procedures and expected net customer impacts.

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~~7.~~g. Applications must state the specific criteria that are proposed for determination of used and useful status of the project, to ensure that no costs are deferred or recovered

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~~8.~~h. Recoverable costs shall be limited to the lesser of actual net incurred project/program costs or Commission-approved amounts, net of savings.

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~~9.~~i. Complex ~~projects~~Projects may be eligible for recovery through the ~~MPIR~~EPRM adjustment mechanism, when supported by sufficient detailed business case analysis and documentation of reasonably quantifiable expected impacts, costs and benefits resulting from such projects.

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~~10.~~j. Parties to the proceedings on applications for recovery of costs through the ~~MPIR~~EPRM adjustment mechanism shall endeavor to complete procedural steps to allow for approval of the application within seven months of the date of application. The Companies acknowledge that the procedural schedule for ~~MPIR~~EPRM for complex projects may take longer than projects that do not affect numerous aspects of the utility's operations, expenses, or earnings.

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~~iv.~~4. Implementation of ~~MPIR~~EPRM adjustments.

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~~1.~~a. The existence of these ~~MPIR~~EPRM provisions does not constitute any assurance of ultimate entitlement to:

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~~a.~~i. ~~approval~~Approval for the commitment of funds for any specific project,

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~~b.~~ii. ~~approval~~Approval to include the costs for any specific project through the ~~MPIR~~EPRM adjustment mechanism, or

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~~c.~~iii. ~~approval~~Approval to begin cost recovery (i.e., depreciation or amortization) or

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~~2.~~b. ~~MPIR~~EPRM adjustments approved by the ~~commission~~Commission in accordance with these Guidelines shall be implemented as an adjustment to the utility's target revenues implemented in accordance with the utility's RBA tariff. ~~MPIR adjustments shall be excluded from the calculation of the basis for determining the RAM CAP and shall not be limited by the RAM Cap.[1]~~

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~~3.~~c. Recovery of ~~revenues for newly~~ approved ~~projects~~costs for Eligible Projects shall be included in the ~~MPIR~~EPRM adjustment in accordance with a Commission order specifying the allowed recovery amount and period.

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~~4.~~d. Collection and reconciliation of ~~revenues~~approved costs recovered through ~~MPIR~~EPRM adjustments shall be implemented through the utility's RBA Rate Adjustment and RBA tariff provisions. The accrual, collection and reconciliation of revenues through the ~~MPIR~~EPRM adjustment mechanism for each ~~Major~~Eligible Project shall be documented and reviewed in the filing and review of the utility's RBA transmittals ~~filed on or before March 31 of each year,~~, as provided in ~~accordance with~~ the utility's RBA tariff.

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~~5.~~e. Accrual of revenues ~~for recovery~~recovered through the ~~MPIR~~EPRM adjustment mechanism for ~~a Major~~an Eligible Project shall commence upon certification of the ~~Major Project~~project's completion and/or in-service date in accordance with terms approved by the ~~commission~~Commission at the time cost recovery through the ~~MPIR~~EPRM adjustment mechanism is approved in the

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~~[1] See Schedule B Order at 94-95 (paragraph 107).~~

~~applicable General Order No. 7~~underlying proceeding for EPRM relief.

~~6.~~f. The accrual of revenues approved for recovery through the ~~MPIR~~EPRM adjustment mechanism shall terminate (i) when and to the extent that the recovery of net costs is incorporated in base rates~~, such as when interim rates become effective as part of a utility's rate case~~ in a separate Commission proceeding, or (ii) when and to the extent that recovery of net costs is affected by other cost recovery means, or (iii) at a time, or according to, criteria specified by the Commission at the time recovery through the ~~MPIR~~EPRM adjustment mechanism is approved.

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~~7.~~g. Any over-recoveries or under-recoveries of revenues under the ~~MPIR~~EPRM adjustment mechanism shall be refunded for collected, with interest, in accordance with the reconciliation provisions in subpart (~~d~~c) above.

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~~a.~~h. MECO may propose a mechanism or methods to provide separate recovery of ~~Major~~Eligible Project costs for its Maui, Molokai, and Lanai divisions, otherwise consistent with these Guidelines.

POST-PHASE 2 D&O SCHEDULES			
	Tariff Development (Table 12)	**Post-D&O Working Group (Table 10)**	**Annual Filing Cycle (Table 13)**
2021			
January	Working Group to review and develop tariff language		
February 9		Working Group convened with a workshop and review of Commission's Prioritized Performance Mechanisms	
February 15	Submission of draft tariffs		
February 23		Working Group meeting	
March 8	Parties' comments on draft tariffs		
March 9		Working Group meeting	
March 16		Parities (and potentially Commission staff's) Statements of position, including suggested refinements, addressing	

		Prioritized Performance Mechanisms.	
March 23		IRs submitted in response to statements of position	
April 1	Commission order addressing tariffs (RAM Provision tariff on expedited review ahead of March 31, 2021)		
April 2		Responses to IRs	
April 9		Parties may submit reply statements of position, based on IR responses.	
April 30	Companies submit tariffs consistent with Commission order, with an effective date of June 1, 2021	Commission order addressing Prioritized Performance Mechanisms.	
May		Companies to submit draft tariff language for Prioritized Performance Mechanisms Commission to review and approve tariffs, expected	

		to take effect June 1, 2021	
June 1	Effective date of tariffs	Effective date of Prioritized Performance Mechanism tariffs.	
June 30		Companies share proposed webpage to post Scorecards and Reported Metrics with Parties and Commission for feedback and approval. Thereafter this webpage should be updated throughout the MRP to timely reflect the Companies' performance, as well as to include any additions or modifications to Scorecards and/or Reported Metrics. Transition to Party-led process. Working Group to meet as determined by Parties or Commission staff, as necessary, to continue development of any PIMs, SSMs, Scorecards, and/or	

		Reported Metrics that show promise of being implemented in near-term during the MRP. Review and approval process for proposals elevated from the Post-D&O Working Group to the Commission for consideration may repeat itself, as necessary, to continue development of any PIMs, SSMs, Scorecards, and/or Reported Metrics that show promise of being implemented during the MRP.	
			* The Annual Filing Cycle for the MRP begins mid-year, such that the Companies’ first biannual report for the following calendar year will be the Fall Revenue Report, which will determine the adjustments to target revenues and the RBA Rate Adjustment effective January 1 of the following year.

October 31			Companies' Fall Revenue Report
November 30			Consumer Advocate's statement of position on Fall Revenue Report
December			Commission order addressing Fall Revenue Report Companies' file tariffs consistent with Commission order, to take effect January 1.
2022			
January 1			Effective date of approved target revenue adjustments and RBA Rate Adjustments based on Commission Order addressing the Fall Revenue Report.
February 28			Companies file schedules and other supporting workpapers for all known attained PIMs/SSMs and EPRM revenue adjustments.
March 31			Companies file Spring Revenue Report

			(Annual Pilot Update and annual PIM & SSM Performance Review included in Spring Revenue Report) Companies file annual RBA Review Transmittals
April 30			Consumer Advocate's statement of position on Spring Revenue Report and RBA Review Transmittals.
May			Commission order addressing Spring Revenue Report and RBA Review Transmittals. Companies file tariffs consistent with Commission order, to take effect June 1.
June 1			Effective date of approved target revenue adjustments and RBA Rate Adjustments based on Commission Order addressing the Spring Revenue Report and RBA Review Transmittals.
October 30			Companies' Fall Revenue Report PIM & SSM Performance Review for any PIM/SSM rewards the

			Companies' seek to recover as part of Fall Revenue Report in accordance with approved PIM/SSM tariffs.
			*Annual Filing Cycle repeats itself throughout MRP
2024			
Comprehensive review of the PBR Framework			

CERTIFICATE OF SERVICE

Pursuant to Order No. 37043, the foregoing Order was served on the date it was uploaded to the Public Utilities Commission's Document Management System and served through the Document Management System's electronic Distribution List.

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COMMISSION

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