PRIORITIZED OUTCOMES, REGULATORY OPTIONS, AND METRIC DEVELOPMENT FOR PERFORMANCE-BASED REGULATION IN HAWAII

Concept Paper to Support Docket Activities

Proceeding to Investigate Performance-Based Regulation (2018-0088)

Hawaii Public Utilities Commission | November 14, 2018

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1 Executive Summary

In April 2018, the Hawaii Public Utilities Commission ("Commission") initiated a proceeding to investigate performance-based regulation ("PBR") (Docket No. 2018-0088) to explore new opportunities for evaluating and updating the State's utility regulatory framework in light of substantial ongoing transformations in Hawaii's electric power systems. The Commission established a two-phase approach to efficiently guide the docket process. Phase 1 focuses on an assessment to determine which components of the existing regulatory framework and which aspects of utility performance should be targeted for improvement. Phase 2 will proceed with developing measures to improve the regulatory framework and, as appropriate, develop incentive mechanisms to address specific priority outcomes.

For Phase 1 (the current phase) of this proceeding, the Commission identified a three-step conceptual framework: (1) identifying priority goals and outcomes to guide PBR development, (2) characterizing and assessing the existing regulatory framework, and (3) identifying components and measures suited for change to attain identified goals and outcomes. The docket process includes three rounds of Technical Workshops followed by Party briefs corresponding to the three steps of the conceptual framework. Preceding each of the Technical Workshops, Commission staff has prepared a concept paper to frame issues, summarize positions, support party deliberations and efficiently move the process forward.

The previous (second) staff concept paper provided a characterization of the existing regulatory framework. During Technical Workshop #2 in September and in the briefs filed in October, Parties provided suggestions regarding which aspects of the existing framework sufficiently support desired outcomes, and instances where changes may be needed.

Commission staff provides this third concept paper to further guide work going forward. Specifically, this paper:

a) Summarizes Parties' stated comments and positions;
b) Suggests a prioritized set of outcomes to guide the remainder of the proceeding;
c) Reviews key applications for metrics and describes possible principles for metric design;
d) Identifies prospective options for changes to regulatory mechanisms (existing mechanisms and potential additions);
e) Describes a "segmented approach" that can be considered to guide future regulatory developments in Hawaii; and
f) Provides guidance to the Parties for the third set of briefs, to focus on metric design and further proposals for changes to Hawaii's utility regulations.

As noted above, this concept paper provides a narrowed list of "prioritized" outcomes for further consideration and refinement in Phase 2. This list is informed by the past Technical Workshops and Party briefs. The prioritized set of outcomes is intended to promote effective progress in the remainder of this proceeding. To support the efficient development of effective metrics in the next steps of the process, the concept paper also provides guidance regarding principles for metrics design. Staff also offers an illustrative mapping of prioritized outcomes onto the type of regulatory mechanisms that may support achievement of that outcome.

The Commission will hold a third Technical Workshop on November 28, 2018, to continue discussion and solicit input from Parties regarding adjustments to existing mechanisms and/or development of new mechanisms to better support achievement of prioritized outcomes. Parties will also explore guidance and principles for metric design. Invited guests will share their experience with metric development in other jurisdictions, to support deeper understanding of how to design useful metrics. After Technical Workshop #3, Parties will file briefs by January 4, 2019, to focus on mapping prioritized outcomes to appropriate regulatory mechanisms and suggestions for metrics to support future outcomes tracking and regulatory updates.

2 Introduction

Phase 1 of the PBR docket is intended to identify prioritized regulatory outcomes that warrant further focus for the development of PBR mechanisms in Phase 2.[1] More specifically, Phase 1 will establish a basis from which to implement modifications or refinements to the current regulatory framework. In order to establish a robust, yet flexible process to focus objectives and advance the proceeding, the Commission has set forth a series of collaborative technical workshops, facilitated by Rocky Mountain Institute, with each followed by focused briefs from the Parties.

This approach encompasses three major steps:

- Identification of regulatory goals and outcomes to serve as guiding principles and to ground an assessment of the regulatory framework;
- Assessment of which outcomes are currently well-served by the regulatory framework and which require greater focus and examination; and
- Determination of which regulatory mechanisms are best-suited to achieve each prioritized regulatory outcome and identification of attendant metrics, where appropriate, to measure the utility's performance in achieving that outcome.

[1] Docket No. 2018-0088, Order No. 35411 at 53.

Step #1

Technical Workshop #1 was held on July 23-24, 2018. Prior to the workshop, Staff submitted a concept paper entitled "Goals and Outcomes for Performance-Based Regulation in Hawaii" to provide the Parties with an initial set of proposed goals and outcomes to respond to, to expand upon, and to offer alternatives. The objectives of Technical Workshop #1 were to: (i) review PBR efforts in other jurisdictions, including tools and processes used; (ii) build a shared understanding of the potential for PBR in Hawaii and a planned approach for the PBR proceeding; and (iii) discuss potential regulatory goals and outcomes for PBR in Hawaii.

On August 24, 2018, Party briefs on Goals and Outcomes were filed to provide specific feedback on staff-proposed goals and to propose alternative regulatory goals and outcomes. These briefs assisted Staff in the preparation for the next step in the PBR process.

Step #2

Technical Workshop #2 was held on September 27, 2018. In advance of the workshop, Staff submitted a second concept paper, entitled "Assessing the Existing Regulatory Framework in Hawaii", to describe how current regulations function and to offer a revised set of regulatory outcomes for the Parties' consideration. The objectives of Technical Workshop #2 were to: (i) deepen collective understanding of existing regulatory mechanisms; (ii) explore how existing structures are or are not supporting achievement of particular regulatory outcomes; and (iii) strengthen Parties' and stakeholders' capacity to collaborate in this work.

On October 25, 2018, Regulatory Assessment Briefs were filed by the Parties to provide insight on the effectiveness of the current regulatory framework by examining how individual regulatory mechanisms help, hinder, or have no impact on the achievement of identified outcomes

Step #3

The third stage of the Phase 1 process continues with Technical Workshop #3, to be held on November 28, 2018. The focus and objectives of Technical Workshop #3 are to: (i) Identify refinements to existing mechanisms that support prioritized outcomes; (ii) Consider new regulatory approaches to support prioritized outcomes not well met by existing regulations; and (iii) Explore common approach and principles for metric design.

Consistent with previous technical workshops, to facilitate the discussion and collaboration in Technical Workshop #3, Staff submits this third concept paper with the following objectives:

- To suggest a prioritized set of outcomes to guide the remainder of this proceeding.
- To review key issues and possible approaches for metric design.
- To illustrate certain considerations for mapping prioritized outcomes to corresponding categories of regulatory mechanisms.
- To explore whether it may be appropriate and beneficial to tailor separate regulatory mechanisms for each individual segment of the power system value chain.

3 Feedback from Regulatory Assessment Briefs

In their Regulatory Assessment Briefs, Parties were encouraged to perform an assessment for each of their top five priority outcomes and how existing regulatory mechanisms impact the achievement of outcomes. To aid the Parties in conducting their assessments, Staff's second concept paper included a suggested structure to evaluate individual regulatory mechanisms' efficacy in supporting the achievement of identified outcomes and characterize inter-dependencies and tradeoffs between outcomes and mechanisms.

The following Parties submitted Regulatory Assessment Briefs: Division of Consumer Advocacy ("CA"); Hawaiian Electric Companies ("HECO"); County of Maui; City and County of Honolulu; County of Hawaii ("COH"); Ulupono Initiative, LLC ("Ulupono"); Life of the Land ("LOL"); Blue Planet Foundation ("Blue Planet"); and Hawaii Coalition, Hawaii Solar Energy Association and Distributed Energy Resources Council of Hawaii ("DER Intervenors").

The Parties submitted detailed and thoughtful feedback on the relationship between existing regulatory mechanisms and potential PBR outcomes during Technical Workshop #2 and through their respective briefs. From the feedback provided to date, several themes have emerged. While many of the Parties provide similar feedback on whether regulatory mechanisms incent or disincentivize achievement of certain outcomes, Parties also make conclusions about the existing regulatory framework that significantly diverge from the findings of other Parties.

A majority of the Parties find the current regulatory model encourages capital spending by the utility as a way of securing utility financial integrity even if it hinders desired goals and outcomes.[2] Some Parties discuss how they find the current regulatory framework to be outdated and inherently flawed as it is not supportive of operational efficiency and fosters a capital bias effect.[3] Some Parties agree that current regulatory mechanisms are merely incremental adjustments to mitigate, but not fully remediate, innate fundamental flaws of the regulatory framework.[4] Other Parties discuss how the existing regulatory framework has succeeded in generally providing good levels of reliability, power quality, and safety, preserving financial integrity, and contains certain elements that are supportive of transformational change and that should be continued and improved with certain modifications.[5]

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[2]*See*, e.g., COH at PDF pages 8, 35, and 46; "DER Intervenors" at PDF pages 3, 5, 7, 9; Ulupono at PDF pages 17, 18, 20, 22, 27, 35; CA at PDF pages 11, 56, 77, 79,

[3]*See*, *e.g*., Ulupono at PDF pages 17, 18, 20, 22, 27, 35; "DER Intervenors" at PDF pages 3, 5, 7, 9; CA at PDF pages 11, 56, 70

[4]*See, e.g.*, "DER Intervenors" at PDF pages 4, 5; Ulupono at 3,

[5]*See, e.g.*, Ulupono at 14, 45; HECO at PDF pages 3, 90, 137, 139; CA at PDF pages 9, 70.

Several Parties believe that PBR should transform the regulatory model so that it discourages utility-capital bias and fosters a more market-based service model that prioritizes outcomes such as cost control, investment efficiency, DER asset effectiveness, social equity, resilience, reducing greenhouse gas emissions, and ensuring capital formation at all levels.[6] Some parties recommend the development of more targeted and well-calibrated incentives but caution that there is substantial risk associated with creating new or significantly modifying revenue adjustment mechanisms with parameters that may not be accurately specified.[7] Parties also warn about the risks associated with designing new mechanisms including unintended consequences, excessive complexity, information asymmetry, free-ridership, and creating metrics that may be at cross-purposes.[8]

There is a need to continue thoughtful dialogue around what will make up the appropriate outcomes, understand the existing regulatory framework, and to guide the proceeding and sufficiently focus efforts in Phase 2. Appendix B provides a detailed summary of the Parties' Regulatory Assessment Briefs and is offered to help advance the conversation.

The following table summarizes the top priority outcomes each Party identified compared to Staff proposed priority outcomes.

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[6]*See, e.g.*, COH at PDF pages 3, 8, 35, and 46; Maui County at PDF pages; Blue Planet at PDF pages 2, 4, 5; "DER Intervenors" at PDF pages 3, 4, 5, 7, 9; Ulupono at 2, 3, 17, 18, 20, 22, 27, 35; CA at PDF pages 5, 11, 56, 70-73; Life of the Land at PDF pages 14-15.

[7]*See, e.g.*, CA at PDF pages 34, 37, 40, 50, 70, 79, 86; Ulupono at PDF pages 11, 20, 21.

[8]*See, e.g.*, Ulupono at PDF pages 11, 20, 21; CA at PDF pages 21, 34, 37, 39, 40, 41, 48, 50, 70, 71, 72, 79, 86.

Table 1. Party Briefs – Responses to Priority Outcomes

Staff Proposed Priority Outcomes	Parties that Support Outcome as Priority	Details
Affordability	Consumer Advocate	Combined Cost Control and Affordability into one outcome
	County of Hawaii	
	County of Maui	
	DER Intervenors	
Interconnection Experience	HECO	Combined Interconnection Experience and DER Asset Effectiveness into one outcome
	Blue Planet	
	DER Intervenors	
Customer Engagement	HECO	Framed this outcome as Customer Engagement
	County of Hawaii	
Cost Control	HECO	Combined Cost Control and Affordability into one outcome
	County of Maui	Framed this outcome as "Cost-Effective System Operations"
	Consumer Advocate	
	C&C of Honolulu	
DER Asset Effectiveness	HECO	Combined Interconnection Experience and DER Asset Effectiveness into one outcome
	Blue Planet	Framed this outcome as "Maximum Optimization of DERs"
	DER Intervenors	
Grid Investment Efficiency	HECO	Framed as "Grid Planning Effectiveness"
	C&C of Honolulu	Framed as "Grid Planning Effectiveness"; could also include "Resource/Grid Solutions Procurement" in this outcome
	Blue Planet	Framed this outcome as "Unbiased Capex/Opex Decisions"
	DER Intervenors	

Table 1. Party Briefs – Responses to Priority Outcomes (continued)

Staff Proposed Priority Outcomes	Parties that Support Outcome as Priority	Details
Social Equity/ Opportunity	Consumer Advocate	Framed this outcome as "Equitable Customer Empowerment"
Capital Formation	Ulupono	Framed this outcome as "Capital Formation at All Levels"
	HECO	
GHG Reduction	Ulupono	Framed this outcome as "Climate Change Mitigation and Adaptation"
	Blue Planet	Framed this outcome as "Carbon Intensity Reduction"
	Life of the Land	Framed this outcome as "Lifecycle Greenhouse Gas Emissions Reductions"
	C&C of Honolulu	
Electrification of Transportation	County of Hawaii	
	County of Maui	
	Ulupono	
	Blue Planet	
Resilience	Consumer Advocate	Framed this outcome as "Cybersecurity"
	C&C of Honolulu	Framed this outcome as "Resilience and Corporate Sustainability"
	Ulupono	Framed this outcome as "Climate Change Adaptation"
	County of Hawaii	
	County of Maui	
	DER Intervenors	
Risk Distribution	Maui County	

Table 1. Party Briefs – Responses to Priority Outcomes (continued)

Staff Proposed Priority Outcomes	Parties that Support Outcome as Priority	Details
Other	Consumer Advocate	Proposes the following outcomes: ▪ Equitable Customer Empowerment ▪ Service Quality/Customer Satisfaction
	C&C of Honolulu	Proposes the following outcome: Transparency
	Ulupono	Proposes the following outcome: Accelerating Renewable Penetration
	Life of the Land	Proposes the following outcomes/objectives: ▪ Decreasing lifecycle carbon dioxide equivalent greenhouse gas emissions ▪ Promoting Access Transparency ▪ Promoting Model Transparency ▪ Promoting Initial Transparency ▪ Promoting Collaborative Transparency

4 Suggested Outcomes for Prioritization in Phase 2

4.1 Why Prioritize Outcomes

In order to promote an effective process going forward, Staff proposes a prioritized set of outcomes to guide the remainder of this proceeding. This list provides a set of key outcomes that require new or different attention in a changing electricity system.

The Phase 1 Convening Order in this proceeding stated that "the commission and Parties will assess which outcomes are currently well-served by the regulatory framework and which require greater focus and examination," leading to a "distilled set of outcomes" to focus the proceeding going forward. This process began with 29 possible outcomes offered in Staff Report #1, which Staff revised to a slightly shorter set of 25 in Staff Report #2, taking into account feedback received in Technical Workshop #1 and subsequent party briefs. Many parties have made comments in Workshops 1 and 2, as well as in Parties' briefs,[9] that a further prioritized set of outcomes is necessary to make effective progress on the objectives of this Proceeding. Staff agrees, and believe that this can allow more effective and targeted consideration of metrics and

[9] *See, e.g.*, HECO Brief at 2; Ulupono at 2.

mechanism design in Workshop #3. More importantly, a narrower set of outcomes will help to focus the subsequent Phase 2 process, allowing attention to a more manageable set of issues and outcomes sought.

The prioritized outcomes discussed in this section include critical areas that need attention to achieve an affordable, clean, distributed, and resilient electricity system. This could provide an ambitious but achievable set of outcomes to use in Phase 2 of this proceeding. While all the outcomes previously laid out in Staff Reports #1 and #2, as well as those proposed by parties, remain important to Hawaii's electricity system, the prioritized set proposed here would be a more manageable number on which to focus future discussions and regulatory design. They are selected to cover what Staff believes to be some of the most significant and immediate areas for attention, to guide updates to regulations in order to allow the HECO companies to better position their utility business for the next decade of planning and operations. While these outcomes are suggested for adoption to guide Phase 2 of this proceeding, staff recognizes that they may not be sufficient to achieve full "end state" reforms of the regulatory framework. Additional outcomes and reforms will likely need attention through other venues in future years.

The outcomes identified as priorities for this proceeding may be addressed in a few ways. Some outcomes may be addressed through development of new performance incentive mechanisms (PIMs), while others might be better suited to changes to existing revenue adjustment mechanisms, or potentially development of new mechanisms. For some outcomes, explicit financial incentives might not be appropriate at this time, but rather the outcome can be tracked through expanded metric reporting or creation of a scorecard (described more fully in Section 5).

4.2 Process for this Prioritization

Through Party input and feedback during Workshop 2, several outcomes emerged as priorities; these include DER Asset Effectiveness, Affordability, Interconnection Experience, Cost Control, and Resilience. Party briefs further emphasized these outcomes, along with some additions for suggested prioritization, as discussed in Section 3 and Appendix B. The below list of prioritized outcomes incorporates this input.

Staff also considered several guiding beliefs and expectations for how the electricity system may change, and what areas need particular attention for improvement. First, Commission staff recognizes that, given underlying economics and customer preferences, Hawaii's electricity grid will likely become increasingly distributed and will need to utilize an expanded set of services from DERs. Relatedly, a distributed, clean energy system necessitates economic and technological innovation may not be adequately supported by current utility regulations.[10]

[10]Parties have expressed support for a similar position*; see, e.g.*, DER Intervenors at 2-3, Ulupono at 22-45.

In addition, the Commission has previously suggested the need for the HECO companies to evolve toward a service-based "platform" model with new functions as a network integrator and operator.[11] These concepts are likewise supported in proposals and regulatory developments elsewhere,[12] and were further raised by many presenters and participants at Technical Workshop #1 and Technical Workshop #2. Recognizing the functions and opportunities inherent in a platform model, we include outcomes that will promote key enablers of a service-based, platform structure (e.g., DER utilization, interconnection, and competition for providing energy services).

To help further clarify and support continued consideration, the proposed outcomes are sorted into two categories: "traditional" and "emergent".[13] 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 accounted for. Affordability, in particular, is of critical importance and should remain a central focus of regulatory reforms. Other traditional outcomes like Safety are long-standing regulatory priorities and are significantly embedded in existing regulatory structures, such that we are confident they will remain paramount and continue to receive substantial consideration as other outcomes and reforms are considered. Notwithstanding the critical importance of traditional outcomes, it is suggested that, given the significant energy transition underway in Hawaii, the near-term focus in this proceeding should, on balance, be placed somewhat more on emergent outcomes.

Emergent outcomes include those that need attention as Hawaii progresses towards a 100% RPS, as the electricity system becomes more renewable, variable, and distributed, and as the HECO Companies pursue opportunities for non-traditional asset investments and services. It is this emergent set of outcomes that reflect the technological disruption and clean energy policy goals that are more acutely driving the need to update utility regulations, and thus require particular focus as new PBR structures are developed. In some cases, a proposed outcome in the emergent set might not be easily or directly addressed by utility regulations (e.g., capital formation for non-utility investments); however, they nonetheless are important enablers of Hawaii's future power system and should be further considered in this proceeding. In other cases, there is significant

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[11]*See* Docket No. 2012-0036, Decision and Order No. 32052, filed April 28, 2014, Exhibit A (the Commission's "Inclinations"), at 13-14, 20; Docket No. 2015-0412, Decision and Order No. 35238, filed January 25, 2018, at 3-4.

[12]*See* Pramaggiore, Anne and Val Jensen; "Building the Utility Platform: Designing for the Future," *Public Utilities Fortnightly*, July 2017 ("Building the Utility Platform"); New York Public Service Commission; "Order Adopting Regulatory Policy Framework and Implementation Plan;" Proceeding on the Motion of the Commission in Regard to Reforming the Energy Vision, filed February 26, 2015.

[13]Some parties have proposed similar organizing principles and criteria for prioritized outcomes; *see, e.g.*, HECO at 2-3, Ulupono at 3.

potential to either update existing regulatory mechanisms or to develop new PIMs and other revenue adjustments that will incent achievement of emergent outcomes.

4.3 Prioritized Outcomes

Based on Parties' input and applying the above down-selection process, staff suggests the following prioritized outcomes to guide the remainder of Phase 1, and for possible adoption in Phase 2. Descriptions and explanations of each outcome follow in the pages below.

Table 2. Suggested Priority Outcomes

Regulatory Goal	Regulatory Outcome	
Enhance Customer Experience	Traditional	Affordability
		Reliability
	Emergent	Interconnection Experience
		Customer Engagement
Improve Utility Performance	Traditional	Cost Control
	Emergent	DER Asset Effectiveness
		Grid Investment Efficiency
Advance Societal Outcomes	Traditional	Capital Formation
	Emergent	Social Equity
		GHG Reduction
		Electrification of Transportation
		Resilience

5 Metrics to Measure Achievement of Outcomes

5.1 Defining Metrics

In the goals-outcomes-metrics hierarchy established at the start of this proceeding, *goals* represent the highest-level objectives for utility regulation and ratemaking, then *outcomes* are a more specific set of factors that derive, in whole or in part, from utilities' operations and business decisions. Outcomes are usually observable and represent ways that the power sector is experienced by customers and market participants, as well as in the larger economy and society.

The next level in the hierarchy, a *metric*, simply defined, is a standard of measurement. In assessing utility and market performance, metrics are central to determine how well a utility is achieving the outcomes of interest and meeting the broader goals set by regulators and policymakers.[14]

If an outcome describes the topic of regulatory interest, then an attendant metric presents how performance in achieving that outcome may be tracked. Metrics are frequently defined by a specific unit of measure (for example, the number of interconnections over a period of time or MW of installed DER). In some cases, more than one metric can be associated with a single outcome. Similarly, a single metric can sometimes inform multiple outcomes.

As outlined in Synapse's "Utility Performance Mechanisms: A Handbook for Regulators," defining a metric typically involves the following:

- Specific data definitions;
- A precise formula used to quantify each metric;
- Data collection and analysis practices and techniques, including identification of the entity responsible for collecting and reporting the data;
- Requirements for measurement and reporting; and
- Verification techniques and designation of entity responsible for verifying data.

This practice is familiar in Hawaii. For example, a common metric for measuring reliability is the sustained average interruption duration index, or SAIDI. The data includes the average number of utility customers and the number of sustained outages, and may or may not exclude outages from major storms. However, to employ this metric, the definition of both a "sustained outage"

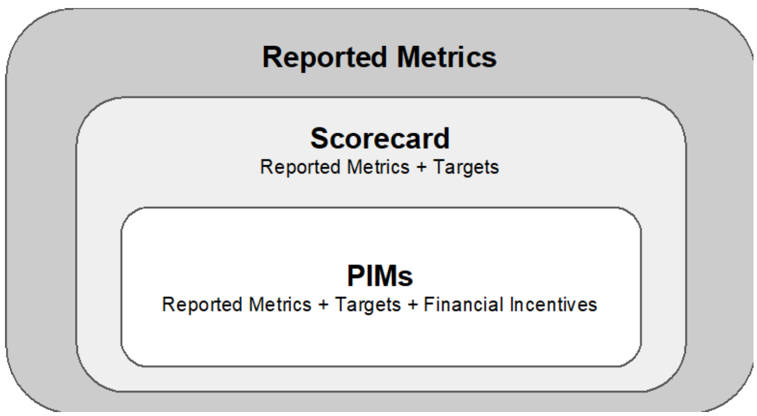
[14] Whited, M., Woolf, T., Napoleon, A. *Utility Performance Incentive Mechanisms: A Handbook for Regulators*, Synapse Energy Economics, March 2015, ("Synapse Report") at 19.

and "major storm" needs to be clarified, the frequency of measurement (e.g., annual or quarterly) defined, and a verification process established.[15]

5.2 Three Primary Applications for Metrics

Metrics can be used in several ways that help track progress against outcomes and encourage exemplary utility performance. These can be broken down according to three primary applications: (1) *reporting requirement*; (2) *scorecard*; and (3) *performance incentive mechanism (PIM)*, as illustrated in the following diagram.

Figure 1. Applications of Metrics



1. Reporting

At a minimum, a metric can serve as a helpful **reporting requirement**, meaning that the data reflected by the unit of measurement is tracked and published to illuminate progress towards a prioritized outcome and, in turn, toward the attendant regulatory goal. For example, the HECO Companies currently report a number of performance metrics on their website, including cost components to customer rates and demand response metrics, among many others.

The simple act of tracking and reporting metrics can incent utilities toward stronger performance by using transparency as a regulatory tool. Reporting standalone metrics can also be useful to inform ongoing market evaluation and policy assessments, and serve as the foundation for developing scorecards or PIMs —the other applications detailed below.

Finally, reported metrics may help to inform the development of revenue adjustment mechanisms as well as to track the efficacy of all regulatory mechanisms over time. Reported

[15]Synapse Report at 20.

metrics may provide an assessment of the impact of regulatory interventions and assist in tracking the achievement of prioritized outcomes over time.

2. Scorecard

When a metric is paired with performance targets, benchmarks, or peer comparisons it becomes a **scorecard**. Typically, a scorecard makes use of clear visuals so that interested persons can easily understand performance and how it compares to targets or to comparable utilities or other regions. Like a reported metric, a public-facing scorecard reports utility performance information in a central location and presents the data in a meaningfully contextualized and transparent manner. Scorecards allow regulators as well as other stakeholders to quickly review and digest utility performance across a number of outcomes and metrics. A scorecard should be readily accessible and featured prominently on the utility, PUC or other website. As with reported metrics, the information provided in scorecards should be clear, concise, comprehensive, and up to date.[16]

By adding a target or appropriate benchmark to a reported metric, scorecards can encourage better achievement of regulatory outcomes than through reported metrics alone. Moreover, for areas of focus that are innovative in nature or where the data to be measured is uncertain, scorecards (comprised of a metric plus a performance target) can be utilized as a "no regrets" test bed before attaching a financial incentive on the path to developing a metric into a PIM.

3. Performance Incentive Mechanism

A **performance incentive mechanism** (PIM) is a metric paired with a performance target and a financial incentive. PIMs provide financial motivation for utilities to improve performance toward established outcomes, or to discourage underperformance. Through the use of a financial award or penalty, a PIM can more strongly promote achievement of a prioritized outcome than a scorecard or reported metric. Examples of existing PIMs in Hawaii include service quality PIMs (SAIDI, SAIFI, and Call Center Performance) and policy PIMs related to the timely acquisition of cost-effective demand response resources from third-party aggregators and the successful procurement of grid-scale renewable energy. Targets established for PIMs may be tied to state energy goals or other established regulatory priorities, and should balance the costs of achieving the target with the potential benefits to ratepayers.

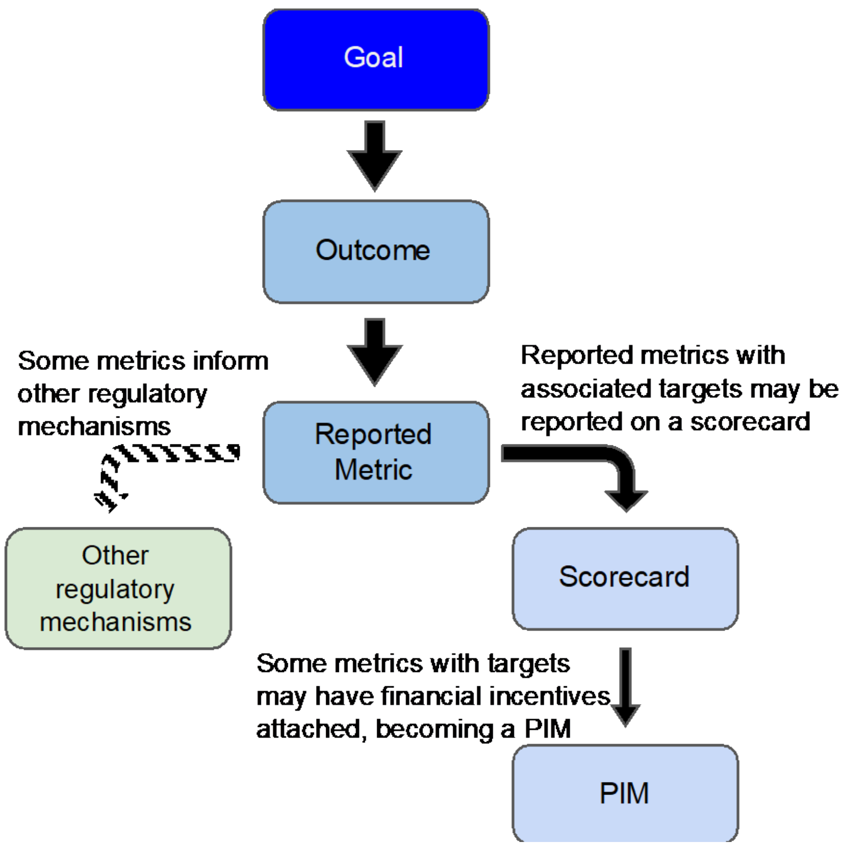
PIM design, as well as application of metrics to other regulatory mechanisms, require significant attention to many important details, such as size of financial incentives, use of deadbands, and

[16]Synapse Report at 31-33.

more. Such details are not the focus of Phase 1, but will likely deserve significant attention in Phase 2.

Figure 2 shows how the different applications of metrics relate to and build off one another. As illustrated, a set of metrics should be designated for reporting; a subset of which can be used in a utility scorecard; and, ultimately, a further subset of metrics can incorporated into PIMs.

Figure 2. Applications of Metrics within the Goals-Outcomes-Metrics Hierarchy



5.3 Principles for Metric Design

To be most effective, metrics must be carefully designed, keeping in mind several key principles. To support further discussion with parties and possible adoption in the proceeding, staff offers a set of five principles for metric design, again adapted from Synapse's "Utility Performance Mechanisms: A Handbook for Regulators".

Metrics should:

1. Reflect desired outcomes
2. Be clearly defined
3. Be quantifiable through reasonably available data
4. Be easily interpreted
5. Be easily verified

Each principle is discussed in more detail below.

Reflect Desired Outcomes. Metrics should reflect desired outcomes and clearly consider the degree to which outcomes are to be achieved. Metrics should report useful data that ties to prioritized outcomes. Some outcomes may require the use of multiple metrics. For example, it is less useful to simply report the number of DER interconnections for the DER Asset Effectiveness outcome. Rather, meaningfully tracking performance against this outcome may necess to examine not just the nominal number of interconnections, but also report the degree to which HECO is effectively leveraging grid services from DER to improve system operations and control costs.

Clearly Defined. In order to avoid confusion or contentious debate, metrics must be clearly defined**.** Definitions should include a precise formula used to quantify each metric. Calculation methods that are precise and unambiguous will allow for useful comparison between utilities (including between Hawaii's islands), possibly with other jurisdictions, and over time. Metric definitions should specify which data is to be collected; how often it should be collected and by whom; and methods for data analysis, reporting, and verification. Metrics should utilize regional or national definitions where possible.[17]

Utilize Reasonably Available Data. Metrics should be able to be quantified using reasonably available data. Rather than requiring costly data collection for information that is not already collected, using data that is already reported can save costs and reduce administrative burden.[18] However, as the electricity system is changing, some emerging outcomes may require the collection of new types of data. New customer- and grid-facing technologies may provide additional transparency into the grid, potentially generating new data resources. This new, possibly more granular data can, in turn, result in improved accuracy and precision.

[17]Synapse Report at 28.

[18]Synapse Report at 29.

Easily Interpreted. Metrics should be easily interpreted to provide stakeholders with a better understanding of utility and market performance. Per-unit metrics (per kWh, or per customer) allow for comparison across utility territories and time, while also ensuring that the interpretation of the metric remains useful even as load or total customers change.[19]

Easily Verified. Metrics should be easily verified. To increase transparency and avoid data manipulation, "the use of straight-forward data collection and analysis techniques should be used."[20] Third-party evaluation can be helpful when evaluating performance tracking and reporting, especially for metrics that have financial incentives or disincentives attached. Third-party evaluation also can help to minimize potential for gaming of measurement and resulting performance incentives.

In addition to the above, some also suggest that metrics should exclusively reflect the impact of factors that are within the utility's control. It is not apparent that this principle should strictly apply to the manner in which metrics are contemplated for Hawaii. As reflected by the three applications for metrics described above, reported metrics, in and of themselves, are important for tracking progress against prioritized outcomes, some of which are influenced by factors that are not directly controlled by utilities (for example, capital formation and even, in some respects, growth in DER assets). Nonetheless, these metrics should be measured and reported to support ongoing market evaluation and regulatory refinements.

The degree of utility control over outcomes is a more significant consideration for those metrics that are used in scorecards and, especially, for PIMs. For these applications, it is important that metrics and mechanism design appropriately reflect factors that the utility has influence over. Even in these cases, however, it might not be appropriate to strictly apply a principle of utility control, as it can be helpful to align and make the utility more responsive to external market factors such as fuel costs. This perspective has also been stated by participants in the PBR proceeding, in workshop presentations and filed party briefs.

5.4 Activity-, Program-, and Outcome-based Metrics

In addition to establishing design principles, it is helpful to understand the nature of underlying activities or system characteristics that metrics measure. Metrics can be categorized as activity-, program-, or outcome-based, depending on what they are measuring.

[19] Synapse Report at 30.

[20] Synapse Report at 31.

Activity-based metrics track specific actions or decisions that the utility is performing directly. Some examples of activity-based metrics might be: recruitment and training of large number of contractors to participate in a new program, developing education/training courses for customers on new technologies, or strategies with assessment of actions taken by customers. Activity-based metrics do not necessarily reflect the achievement of a desired outcome since they tend to focus on intermediate steps toward achieving an outcome; however, these metrics are helpful indicators of progress, especially when direct measurement is difficult.

A step away from process and toward results, **program-based metrics** measure the relative success of utility programs. For example, a program-based metric for load reduction might measure peak reduction in MW attributable to customers that are participating in an event-based demand response program, compared to an established baseline where performance is measured *ex post* against a forecasted "business as usual" scenario and normalized for exogenous factors like weather. They can, in some cases, unduly emphasize narrow programs that may constrain more systemic changes that are needed. Furthermore, in some circumstances, they may operate to limit potential for new and innovative approaches to achieve outcomes. In addition, measure-by-measure estimation can also be subject to disputes over baseline assumptions, calculation methods, and the challenge of "proving the counterfactual."[21]

Outcome-based metrics can be used when direct measurement of results is possible. Examples of outcome-based metrics include pounds CO2/MWh for carbon intensity, or an absolute MW measurement for total system peak. If applied well, outcome-based metrics can allow the utility flexibility in choosing which programs and technologies should be used for achieving outcomes. Under the right circumstances, outcome-based metrics can allow utilities to determine the most effective strategy to achieve policy objectives, including development of new business strategies that would not be considered under narrower, program-based metrics, while somewhat relieving regulators from dictating program terms. By measuring changes at a system level and not as siloed programs or activities, outcome-based metrics can also mitigate disagreements over counterfactuals and attribution.

Outcome-based metrics can be appropriate where programmatic inputs are not simple to isolate, and where the desired outcome is best pursued by a holistic approach and a range of activities that jointly influence the outcome (as well as the activities of customers and third parties). However, outcome-based metrics have limitations as well, including concerns that it may be unfair or risky to attribute to utilities results that are significantly influenced by exogenous factors

[21]Orvis, Robbie. *Avoiding Counterfactuals in Performance Incentive Mechanisms: California as a Case Study*, America's Power Plan, April 2016.

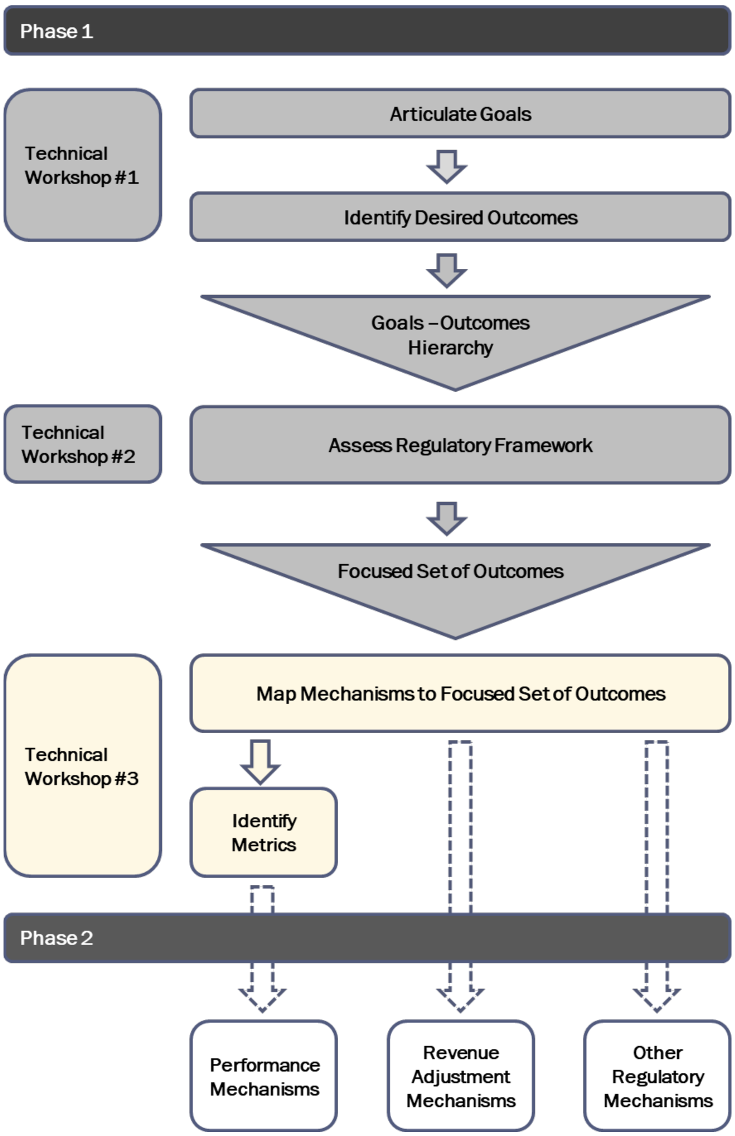
such as weather, economic activity, or the decisions of other market participants. Nonetheless, outcome-based metrics can be a useful measure of overall achievement of outcomes, and tracking these as metrics alone does not necessarily suggest that the metric be directly tied to financial incentives.

In practice, a mix or blended portfolio of metric types is warranted. In particular, program-based metrics can be helpful during transitional phases of market development and while less-established outcome-based metrics are explored. Activity-based metrics may also be appropriate in limited circumstances, such as for tracking progress on system planning or data sharing.

6 Addressing Priority Outcomes

After setting forth a focused set of outcomes, the next step in the Phase 1 process is to match each of these prioritized outcomes to one or more corresponding categories of regulatory mechanisms. The selected regulatory mechanism category should represent that which is best able to drive achievement of the outcome. This exercise of mapping prioritized outcomes should result in grouping the outcomes into one or more of the three PBR element pathways identified in Section 6.1 below.[22]

Figure 3. PBR Process Design



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[22]Order No. 35542 at 50.

6.1 Categories of Regulatory Mechanisms

Prioritized Outcomes can be mapped to one of three categories of regulatory mechanisms: (1) revenue adjustment mechanisms; (2) performance mechanisms; and (3) other regulatory mechanisms. Each category is described further below.

Revenue Adjustment Mechanisms

Some prioritized regulatory outcomes may be best addressed through the use of revenue adjustment mechanisms. Revenue adjustment mechanisms may be preferred to other categories, such as performance mechanisms (e.g. performance incentive mechanism (PIM)), where the outcome relates to a utility's structural financial incentives or where a single corresponding metric is difficult to determine or measure. For instance, various jurisdictions have utilized revenue adjustment mechanisms such as multi-year rate plans coupled with attrition relief mechanisms to incent cost control between rate periods.

With respect to the current regulatory framework, the following existing mechanisms would fall under the revenue adjustment mechanisms category: Multi-Year Rate Plan (MYRP), Revenue Decoupling (RBA), Revenue Adjustment Mechanism (RAM), RAM Cap, Major Project Interim Recovery (MPIR) Guidelines, Earnings Sharing Mechanisms (ESM), and Energy Cost Adjustment Mechanism (ECAC/ECRC) and Purchased Power Adjustment Mechanism (PPAC).[23]

Performance Mechanisms

Performance mechanisms include possible regulatory tools such as scorecards, and PIMs.

Currently, the HECO Companies are required to maintain and prominently publish on the Companies' web sites a list of performance metrics covering renewable energy, utility costs, safety and reliability, and other indicators. Data for most of the metrics is reported on a quarterly basis for the most recent two years and on an annual basis for the most recent ten-year period. Although some of the metrics are utilized in existing PIMs, i.e., SAIDI and SAIFI, most of the Companies' currently reported metrics do not include performance targets or financial incentives.

Other Regulatory Mechanisms

In cases where certain regulatory outcomes may not be sufficiently addressed by any of the above regulatory mechanisms, it may be necessary to review and consider strategic changes to the current regulatory framework. This could include mechanisms that help move away from the existing capital investment paradigm (e.g., mechanisms to encourage the pursuit of cost-effective, service-based solutions, including, but not limited to, non-wires alternatives). Other options may include new revenue opportunities to enable a future electric utility

[23] Descriptions of these regulatory mechanisms are provided in PBR Staff Report #2, at 19-23.

platform business model (e.g., provision of new value-added services to customers and third-parties).

Examples of possible mechanisms under this category:

- Shared Savings Mechanism
- An approach equalizing treatment of capital or operational solutions
- Non-Revenue Mechanisms/Provisions (e.g., integrated grid planning; NWA procurement processes)
- All-source procurement approaches
- New revenues from value-added services

6.2 Mapping Prioritized Regulatory Outcomes with Regulatory Mechanisms

Once prioritized set of outcomes is established, the next step in the Phase 1 process is to match each priority outcome to a regulatory mechanism category. Mapping outcomes to categories of regulatory mechanism will provide a focused foundation for success in Phase 2, where the design and development of specific PBR elements to drive achievement toward each outcome will occur.

Table 3 below highlights how one might map the prioritized outcomes set forth in Section 4 to one of three categories of regulatory mechanisms. To give additional context for this mapping exercise, the table also lists examples of potential regulatory mechanisms that might be utilized under each category. Staff stresses that this table is not definitive or exhaustive, but merely illustrative in nature and should serve primarily to facilitate discussion in Technical Workshop #3 and to help inform the Parties' Metrics briefs.

Table 3. Illustrative Table to Outline Prospective Approach

Goal	Outcome	Mechanism Category	Potential Regulatory Mechanisms
Enhance Customer Experience	Affordability	Performance Mechanism	Scorecard
	Reliability	Performance Mechanism	Scorecard PIM
	Interconnection Experience	Performance Mechanism	Scorecard PIM
	Customer Engagement	Performance Mechanism	Scorecard PIM

Goal	Outcome	Mechanism Category	Potential Regulatory Mechanisms
Improve Utility Performance	Cost Control	Revenue Adjustment Mechanism Performance Mechanism Other	MYRP / Attrition Relief Mechanism Shared Savings Mechanism Scorecard
	DER Asset Effectiveness	Performance Mechanism Other	PIM Planning (e.g., IGP)
	Grid Investment Efficiency	Other	Shared Savings Mechanism Capex/Opex equalization
Advance Societal Outcomes	Social Equity	Performance Mechanism Other	Scorecard PIM LMI-focused Programs
	GHG Reduction	Performance Mechanism	Scorecard PIM
	Electrification of Transportation	Performance Mechanism Other	Scorecard New value-added services
	Capital Formation	Performance Mechanism	Scorecard
	Resilience	Performance Mechanism Other	PIM Planning (e.g., IGP); Microgrid Service Tariff

Affordability: This outcome has been a longstanding priority of utility regulation and should remain an area of focus in this proceeding, particularly as Hawaii customers experience the highest electric retail rates in the nation. This outcome is very closely related to the priority outcome of Cost Control. While Cost Control is likely best addressed by revenue adjustment mechanisms and possibly other regulatory mechanisms, Affordability, can be viewed as the customer-facing side of the cost reduction equation – to track and ensure that savings are resulting in lower customer bills and not accruing solely to shareholders. Accordingly, this prioritized outcome is likely best addressed through performance mechanisms, e.g., scorecards, to track performance against metrics such as average monthly bill by rate class.

Reliability: Having a reliable supply of electricity is more than just a convenience. It's a necessity. Our economy – and our way of life – depend on it. For utilities, maintaining a high level of reliability requires constant commitment and is central to the core functions of providing safe, reliable, and affordable electricity for all customers. The North American Electric Reliability Council's definition of reliability encompasses two concepts: adequacy and operating reliability. Adequacy is defined as "the ability of the system to supply the aggregate electric power and energy requirements to the consumers at all times." Operating reliability is defined as "the ability of the system to withstand sudden disturbances such as electrical short circuits." The level of reliability is typically measured by the frequency, duration, and magnitude of the loss of service to total customers.

Performance mechanisms would appear to be the category well-situated to address Reliability. PIMs are already in place for SAIDI and SAIFI. Additional scorecards or PIMs may need to be considered through the course of this proceeding.

Interconnection Experience: As the number of DER, community-based renewable energy (CBRE) projects, and third-party-owned, grid-scale resources on Hawaii's electric grids increase, a streamlined process for connecting these technologies is needed to ensure interconnection is efficient and seamless. Numerous aspects and phases of the interconnection experience are important for customer services, grid management, and achievement of Hawaii's energy policy goals. This is an emergent outcome of the electricity system for the simple reason that the interconnection of many thousands of customer-sited DERs was not a practical consideration historically. As the power system shifts to reflect the priorities and needs of a modern energy network, including growing customer-sited DER, that evolution must include improved interconnection processes.

Interconnection Experience may be best addressed through the use of performance mechanisms. Depending upon the metrics developed for this outcome, scorecards could be developed comparing the utility's interconnection performance to that of its peers. In addition, PIMs might be appropriate to financially incent expedient interconnection time for customers.

As with most (if not all) outcomes, other categories of regulatory mechanisms may have an indirect effect on the achievement of Interconnection Experience. For example, with respect to revenue adjustment mechanisms, a decoupling mechanism may mitigate a utility's throughput incentive and lessen the financial disincentive to facilitate DER interconnection and adoption.

Customer Engagement: Utilities 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. Expectations for Customer Engagement have increased along with technological advances. Given increasing reliance on distributed resources, successful customer engagement will likely be a key component for Hawaii to meet its clean energy goals.

As a result, it may be important to track customer participation in DER, DR, and CBRE programs, as well as the level of quality program administration and innovative product and service offerings on the part of the utility. Although Customer Engagement poses some inherent difficulties for direct measurement, some helpful proxy measurements may be developed. Accordingly, Customer Engagement may be best addressed through performance mechanisms, driving exemplary utility performance in this area by use of scorecards or, perhaps, carefully tailored PIMs.

Cost Control: Cost control is a traditional regulatory outcome, and several of Hawaii's existing regulatory mechanisms are designed to ensure reasonable utility costs. As shifting grid economics and RPS goals bring new investments in the grid and non-traditional assets (such as EV infrastructure), heightened attention is needed to control costs. As other changes to the regulatory framework are contemplated in this proceeding and elsewhere, Cost Control should remain a continued priority.

As illustrated in Table 3, multiple regulatory mechanisms could be assigned to this priority outcome. Possible regulatory mechanisms include Revenue Adjustment Mechanisms (such as modifications to the existing MYRP/RAM/RAM Cap), Performance Mechanisms (such as scorecards) as well as Other Regulatory Mechanisms (such as a shared shavings mechanism).

DER Asset Effectiveness: The HECO Companies' service territories have experienced some of the highest DER adoption in the world. The trend toward more dynamic and distributed power systems is expected to continue, as a result of underlying economics, customer preferences, and the State's policy goals. As the electric utility network continues to transform from one defined by central station generation and one-way power flow to a system in which there are many thousands of DERs and multi-directional power flows, there is an emergent and increasing need to ensure that these resources play an integral role in the functions and balancing of the network. This outcome relates to other priorities, including Affordability, Cost control and Grid Investment Efficiency, as more effective utilization of DERs may help to defer large capital investments and increase grid reliability, at lower costs than traditional solutions.

DER Asset Effectiveness may map best to the Performance Mechanisms category, as targeted PIMs, with carefully crafted underlying metrics, could help to incent greater utilization of customer-sited assets and potential mitigate any capital bias that would cause DER solutions to be disfavored by the utility.

Grid Investment Efficiency: Given the high cost of electricity for Hawaii customers, and the increasing availability of alternatives to traditional electric service, it is imperative to pursue a broad set of solutions for grid needs irrespective of the nature of the investments (i.e., investment in utility-owned capital expenditures versus third-party provided service-based solutions). Focusing on efficient grid investment could provide an opportunity to correct the capital investment bias that is inherent in conventional electricity regulation. New investment approaches, both for the combinations of technologies considered, as well as the procurement processes used to identify and evaluate options, may help reorient utilities' financial incentives to encourage pursuit of different investment portfolios and more creative solutions. Under this outcome, attention will also be needed to the relative merits and comparative value of investment and asset ownership by non-utility actors, including independent power producers, third-party solution providers as well as end-use customers.

Other regulatory tools or new mechanisms may be best-suited to address Grid Investment Efficiency. Potential mechanisms might include shared savings mechanisms or, perhaps, in the longer-term, an approach that could level the playing field between utility-owned capital solutions and third-party service solutions.

Social Equity: It is a public policy imperative that, to the extent possible, all customers fairly share in the costs and benefits associated with Hawaii's energy transition. If social equity is not a priority in ongoing regulatory development, there is a risk that the direct benefits of electricity system changes will unfairly accrue to a limited portion of customers and companies.

Performance Mechanisms may be suited to address this prioritized outcome, either through scorecards or PIMs. As one possible example, a targeted PIM could be used to incent greater cooperation and collaboration with energy service providers focused on low-to-moderate (LMI) customers, such as Hawaii Energy. Moreover, other regulatory tools, including, for instance, targeted energy efficiency programs or CBRE projects could help ensure that LMI customers are able to realize cost savings through customer investments and programs.

Capital Formation: Capital formation is the ability of the utility to attract debt and equity at a reasonable cost, in order to conduct its business including investments in necessary new assets. Beyond the utility, capital formation also can refer to the ability of third parties and customers to invest in new energy technologies at sufficient scale. Traditionally, this outcome has been focused almost exclusively on the utility's credit rating and financial health. Going forward, this outcome could begin to consider broader capital flows in the electricity sector. The increasingly diverse and competitive marketplace for energy services suggests that regulations do not serve their societal objectives through a narrowly constructed view to only promote the financial health of the utility. Rather, while indisputably an important regulatory consideration, the utility's financial profile should be evaluated along with other sources of market investment that can serve customer and societal needs.

At this time, in what are the early stages of this proceeding and exploration of PBR approaches, it is not immediately clear how capital formation may translate into regulatory reforms. However, given its broad significance and underlying relation to activities necessary to accomplish state energy policy goals, it will be helpful to maintain Capital Formation as a priority outcome for further attention and contemplation. Including this outcome among others can, at a minimum, provide a useful reference to monitor overall conditions and place the utility in the context of broader market health. Accordingly, it may be most appropriate to address Capital Formation via performance mechanisms.

A proposed performance mechanism considered for this regulatory outcome may seek to support capital formation at three related levels: the utility level, third-party market participants, and the consumer. An outcome such as Capital Formation, however, may be best-suited to a reported metric approach, where it can provide a useful reference to monitor overall conditions and place the utility in the context of broad market health. This could be measured in many ways; for example, through a record of total annual investment in the State's electricity sector; total non-utility investment in the electricity sector; along with the utility's credit rating.

GHG Reduction: Reducing the greenhouse gas (GHG) emissions of Hawaii's electricity system is a priority, as evidenced by HB 2182, recent legislation that sets a goal of carbon neutrality by 2045. Where the 100% RPS standard imposes a requirement to increase the share of renewable energy supply in the power system, the GHG Reduction outcome offers a different focus aimed more directly at reducing emissions attributable to the power system. This is especially important as increasing portions of the economy may be electrified in coming years, including transportation. Traditional utility regulation was not crafted with carbon reduction in mind but, going forward, regulations may seek, in their design, to support cost-effective decarbonization of the power system.

This prioritized outcome may be best addressed through Performance Mechanisms, such as reported metrics or scorecards to track utility performance, and potentially compare it against peer utilities. If, over time, the collected data warrants further examination and regulatory attention, a prospective scorecard could be considered for elevation to a PIM.

Electrification of Transportation: Electrification of Transportation ("EoT") represents an area of key interest in the State, as evidenced, in 2017, by Hawaii's four counties announcing a commitment to 100% clean transportation by 2045 and the conversion of their own fleets by 2035. The HECO Companies have stated the important potential of EoT to help achieve both greater clean energy and customer benefits. EoT also constitutes an emerging business opportunity for utilities, as it presents an opportunity for increased customer engagement, as well as to offer additional value to customers. Expanding charging infrastructure further raises questions about the role of the utility as opposed to other third-party providers. EoT may fundamentally change the grid, making it even more distributed and integral with broader economic and social activities. These changes provide both an opportunity and a challenge, which should be evaluated further for the ways in which EoT can be incorporated into utility regulations.

At this stage of EoT market development and electric vehicle adoption, existing regulatory mechanisms may incent utility support of this outcome already. Accordingly, it might be sufficient to address this outcome through the use of performance mechanisms, such as a scorecard, to track customer adoption and monitor grid preparedness. Appropriately tailored metrics could monitor whether further regulatory support is needed in the future.

Resilience: Resilience is the ability of a system or its components to adapt to changing conditions, as well as withstand and rapidly recover from disruptions. Resilience can be thought of as having four dimensions: (1) robustness (the ability to absorb shocks and continue operating); (2) resourcefulness (the ability to skillfully manage a crisis as it unfolds); (3) rapid recovery (the ability to get services back as quickly as possible); and (4) adaptability (the ability to incorporate lessons learned from past events to improve resilience).[24]

Threats to the grid can be both external (e.g., physical and cyber-related attacks from adversaries) and internal (e.g., aging infrastructure and the increasing adoption of variable generation). In light of the risks facing the electric power system, heightened further by Hawaii's geographic isolation and exposure to natural disasters, there is an increasing need for attention to resilience.

As illustrated in Table 3, multiple regulatory mechanisms could be assigned to this priority outcome. Possible regulatory mechanisms include performance mechanisms, either reported metrics, scorecards, or even PIMs, if appropriately designed and implemented. Furthermore, Resilience could be addressed through other, non-revenue regulatory mechanisms, such as integrating resilience into grid planning or through the development of microgrid service tariffs.[25]

In sum, staff stresses that the above table is merely illustrative in nature and serves to facilitate further thought and discussion by the Parties and in furtherance of their Metrics briefs. Parties should view the above as such and indicate agreements or disagreements as well as proposed alternatives, as appropriate.

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[24]*See Resilience of the U.S. Electricity System*, at 1, *citing* National Infrastructure Advisory Council, A Framework for Establishing Critical Infrastructure Resilience Goals (Washington, D.C.: National Infrastructure Advisory Council, 2010) *available at* https://www.dhs.gov/national-infrastructure-protection-plan.

[25]*See, generally* Docket No. 2018-0163, Order No. 35566, "Opening the Docket," filed July 20, 2018.

7 Regulatory Market Structure in Hawaii: A Segmented Approach

A primary question posed at this stage of Phase 1 is how the regulatory framework can systematically evolve to effectively drive achievement of priority outcomes. This question is addressed, in part, by exploring which regulations may most effectively drive achievement of particular outcomes, as reflected in Section 6 above. As we look to better align customer and societal interests with utility incentives, it is important to recognize that individual regulatory mechanisms operate within a sector that has several differentiable segments: (1) **generation**; (2) **transmission and distribution** ("T&D"); and (3) **behind-the-meter** ("BTM").

This section examines how a segmented regulatory approach may best ensure that the overall regulatory framework is optimized, efficient, and effective. Stated simply, given divergent technological and economic characteristics, it may be prudent to tailor separate regulatory mechanisms for each individual segment of the power system value chain. This concept is explained in the remainder of this section.

7.1 Shifting of Historical Utility Functions

Driven by shifts in a multitude of circumstances, including economic factors, customer preferences, and technological innovation, the traditional set of electric utility functions is shifting. For roughly a century of electric industry practice, natural monopoly conditions were presumed to exist at every level of the value chain. In recent decades, there has been an evolution in the role of electric utilities as monolithic vertically integrated businesses towards progressive incorporation of competition and market mechanisms. This evolution has proceeded differently for each of the generation, T&D and BTM segments. At the federal level, most bulk generation, transmission resources and aggregation of BTM resources are now subject, on a multi-state regional level, to rules that provide for substantial open-access, competition and market pricing. Distribution services and local generation resources remain the responsibility of individual utilities subject to state price regulation.

In Hawaii, which is not subject to such federal regulation (i.e., regulation by FERC, NERC or most other Federal Power Act provisions), competition has similarly been introduced primarily in the generation and BTM segments in accordance with State regulatory provisions. Utility-scale generation is procured by each utility, subject to a competitive bidding framework. Distributed generation is subject to regulatory policies governing and restricting utility ownership of BTM generation. A vigorous, largely unregulated market for BTM generation has developed. BTM efficiency measures are promoted and incented by a "third-party" ratepayer-funded demand-side management services contractor. The core functions of generation planning and operations, responsibility for service reliability and transmission and distribution remain fundamentally with the utility as traditionally regulated functions presumed to have natural monopoly characteristics.

Present day trends, particularly those pertaining to renewable energy integration and DER, underscore a continuing shift in which an increasing number of utility functions across the value chain can be served by emerging options and choices and may appropriately be subject to more competition and updated market structures.[26]

7.2 Industry Structure Segments in Hawaii

As noted above, the electric power sector can be framed in terms of three component segments: generation, transmission and distribution, and behind-the-meter.

Figure 4. Electric Power Sector Segments

The **Generation** segment is composed of electric generating stations (both utility- and third-party owned) that make up the bulk power system. This segment may also include generation that is interconnected to the distribution system in-front-of the meter. Over time, the generation segment may increasingly include emergent technologies that are not strictly "generation" in the traditional sense, such as battery energy storage systems and synchronous condensers.

The **T&D** segment represents the cyber-physical infrastructure that serves as the electric network. This includes transmission lines, substations, the distribution system and metering technology – as well as the communications, sensing, measurement, and computing systems that work together to operate the power system.

The **BTM** segment includes the various distributed energy resources ("DERs") emerging at the grid edge, interconnected on the customer's side of the point of common coupling. These DERs include rooftop solar photovoltaics ("PV"), distributed battery storage systems, customer-sited EV charging infrastructure, energy efficiency measures and flexible/controllable loads.

When regulation was first applied to the electric industry, no categorical distinction was necessary regarding how these segments were regulated. Over time, however, it has been recognized that natural monopoly attributes apply differently to each segment, with corresponding changes incorporating some competitive and market mechanisms to specific

[26]*See* Rocky Mountain Institute, "Reimagining the Utility: Evolving the Functions and Business Model of Utilities to Achieve a Low-Carbon Grid," January 2018, ("Reimagining the Utility Report") at 9.

segments. Given the distinctions between the characteristics of each segment, crafting regulatory approaches targeting each individual segment may yield a more cost-effective regulatory system that is better aligned with the public interest. Such a differentiated segmented approach is consistent with the evolution of regulation in Hawaii.

Generation

Hawaii's generation system consists of a mix of utility-owned and independent-owned (IPP) generation units. New generation is expected to be acquired through competitive solicitation, either via the Competitive Bidding Framework[27] - which was adopted in 2006 to facilitate an increase in the number and diversity of wholesale suppliers - or through a potential successor competitive solicitation process. By driving more competitive solicitations (also known as requests for proposal, or RFPs), benefits can accrue to consumers when all potential generators competitively reduce costs and increase innovation.[28] Recent technological innovations and state policy goals have only enhanced the rationale for fostering effective competition in the procurement of bulk power resources.

Transmission and Distribution Network

Utilities manage the assets, control connections, plan expansions, and manage operations of the T&D network. Historically, there were few substitutes for traditional T&D solutions and planning activities related to the T&D network were, primarily, processes internal to the utility. Today, many of the utility core services provided on the T&D network retain natural monopoly characteristics and may continue to do so for the foreseeable future. This is largely because it would be extremely intrusive, and almost certainly inefficient, to have two sets of grid networks operating side-by-side.

Even as the T&D segment is likely to retain most natural monopoly characteristics for the foreseeable future, new functions and capabilities are needed, particularly for the distribution system. The widespread adoption of DER combined with grid-scale resources to create a portfolio of renewable generation and grid services will necessitate a continued evolution of the utility toward a network systems integrator and operator to meet customer expectations, achieve clean energy goals, and provide safe, reliable and affordable electricity. Indeed, as DER adoption has reached nontrivial levels, electric utilities increasingly need to manage two-way power flows and facilitate the provision of energy and grid services from customer-sited resources, enabling meaningful DER integration to ensure a reliable, secure, distributed, and clean energy network. To that end, the previous utility roles of forecast, plan, and build

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[27]*See* Docket No. 03-0372, Decision and Order No. 22588, filed June 30, 2006 ("D&O 22588").

[28]*See* D&O 22588 at 10; Peter Fox-Penner, *Smart Power: Climate Change, the Smart Grid, and the Future of Electric Utilities*, Island Press: 2010 ("Smart Power"), at 164-166.

transmission and distribution infrastructure need to transition to a more integrated and robust set of functions for planning, operations, and market facilitation.[29]

Going forward, it is anticipated that power system planning and procurement will need to be fully integrated across all segments of the value chain. Technology and planning processes continue to evolve, such that non-utility services are becoming comparable and substituted for T&D network services in some instances. In recognition of these developments, the Commission currently requires the HECO Companies to evaluate non-wires solutions (NWS) such as energy storage, demand response, and smart grid resources as part of any economic justification for new transmission or distribution system projects. Such an approach is consistent with the exploration of non-wires alternative (NWA) procurements in other jurisdictions, such as California and New York.

Building upon successes elsewhere, the HECO Companies have suggested a process to address the emergent need for integrated grid planning and procurement. As proposed, the Companies' Integrated Grid Planning process would holistically consider grid needs across generation, transmission, and distribution systems, while simultaneously integrating an all-source procurement that allows NWS to compete against traditional solutions to deliver customer value.

<u>Behind-the-Meter</u>

The BTM segment of the power system has seen extensive technological and economic developments over the last two decades. For many years, the BTM segment was taken as a given, considered only to encompass price-inelastic consumption, with no attention to its potential as a system resource. Technology advancements have enabled DER sited in the BTM segment to play an increasing role in the power system. The widespread adoption and emergent capabilities of DER have introduced new options for assets and services at this segment of the system to serve needs traditionally provided at the generation and T&D levels. For example, rooftop solar PV coupled with advanced inverters can provide energy and ancillary services that, historically, were the sole domain of resources located in the generation segment of the electric industry value chain. Similarly, in some cases, distributed energy storage and flexible, responsive customer loads can provide cost-effective alternatives to traditional, T&D network solutions.

The growth and evolution of DER is anticipated to continue apace and with it will come the enhanced ability for customers to meaningfully participate in electricity markets via dynamic pricing, demand response (DR) and DER programs, or NWS procurements. These changes are expected to include the integration of consumers as active participants in balancing the electricity supply/demand equation.[30] Coupled with enabling grid modernization investments in the T&D segment, continued DER advancements should empower customers with meaningful choice and

[29]*See* Reimagining the Utility Report at 9.

[30]*See* Smart Power at 167.

control when it comes to the provision and consumption of energy services. These trends, in turn, could yield greater innovation in new value-added services and energy applications. By fostering adequate competition in the BTM segment, one might guard against excess market power control by the regulated utility that could suppress innovation and limit customer choice.

In Hawaii, the BTM segment of the power system value chain is largely a competitive landscape. Indeed, various policy guidelines have been developed in order to preserve the competitive nature of this segment and mitigate any unfettered extension of the utility's regulated service and attendant market advantages, which could unduly decrease customer choice, innovation, and the cost-effectiveness of customer-sited energy services.

For instance, in determining whether the utility should be permitted to provide distributed generation on a customer's site, the Commission noted that permitting such activity may create a barrier to entry for prospective competitors "to the extent the utility has market advantages attributable to its historic status as the sole provider of electric retail service, rather than its present merits as may be related to a particular distributed generation project."[31] Moreover, in addition to the potential for a shift in risk away from the DG customers and to the captive ratepayers overall, "[t]he utility would also have an opportunity to dominate the new market, whereas electricity customers may be better served if they have alternatives that multiple and diverse suppliers of distributed generation would bring."[32] Accordingly, the Commission determined that "the utility should not be allowed to provide distributed generation services on a customer-owned site as a regulated service," except under specific circumstances.[33]

To date, the BTM segment is characterized by resources compensated for energy and grid services through administratively set rates and programs, such as DER tariffs and grid service tariffs via the DR Portfolio. In the future, in order to unlock the full potential of BTM resources, simplified interconnection, tariff, and programmatic approaches need to be meaningfully integrated into power system planning and supplemented by more market-based approaches, such as NWS procurements.[34]

[31]Docket No. 2003-0371, Decision and Order No. 22248, ("D&O 22248"), at 17.

[32]D&O 22248, at 17.

[33]D&O 22248, at 17-18.

[34]*See, e.g.*, Docket No. 2018-0165, "Hawaiian Electric Companies' Integrated Grid Planning Report," filed July 13, 2018 ("IGP Report"), at 14, Figure 3: Integrated Grid Planning & Solution Sourcing Process; Brenda Chew, Erika H. Myers, Tiger Adolf, and Ed Thomas, "Non-Wires Alternatives: Case Studies from Leading U.S. Projects," Smart Electric Power Alliance, November 2018.

7.3 Network System Integrator and Operator: Toward a Platform Utility

The energy transition underway in Hawaii may also require enhancements to utility functions that span the power system value chain. In addition to the three segments described above, an additional lens to consider is the concept of a platform utility.[35]

A pipe model has characterized the utility business since its inception. The typical electric utility operated by a linear process, with a focus on generating, distributing, and selling kilowatt-hours and ancillary services. More recently, as the grid is made smarter with new controls and information support, utilities are sometimes envisioned to evolve to a platform of similar character in the future, as more DER and customer-centric energy management options become widespread.

"Platforms," as the term is widely used in economics and management literature, refer to mechanisms for serving multi-sided markets via networks and information technology that bring together buyers and sellers. In connecting these participants, platforms enable growth in the number and variety of new transactions that would otherwise not take place. For example, intermediaries such as Amazon and Visa provide platforms for shopping and instantaneous, distributed retail borrowing, respectively. The value of the platform increases as both the number of users and the linkage of the platform to other economic processes (such as compatibility with hardware choices for cellular phones, etc.) increases. These are referred to as positive network effects and economies of scope.[36]

While traditional core utility functions remain critical roles of the Hawaiian Electric Companies, technological developments and changing customer preferences are compelling the Companies to act much more like a platform – to foster transactions and connections between producers and consumers of energy services. The HECO Companies' DR Portfolio is one leading example of this transformation already underway. Having unbundled ancillary services, the DR Portfolio's grid service tariffs facilitate the third-party aggregation of customer-sited resources to meaningfully contribute to system reliability.[37]

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[35]While the physical and business structures of this "platform utility" remain in development, some experts have suggested that a utility network platform can be conceptualized as being composed of four layers: (1) the cyber-physical asset base; (2) system operations and planning; (3) transactive commodity exchange; and (4) services and solutions marketplace. Building the Utility Platform at 39.

[36]The Brattle Group, "Evolving Business and Regulatory Models in a Utility of the Future World," June 2017, ("Brattle Report") at 7.

[37]Through the provision of capacity, fast frequency response and regulation reserves, the DR Portfolio highlights how BTM resources are increasingly able to provide grid services that were once the sole province of other segments of the value chain – in this case the generation segment.

Although the platform concept for energy network services is an attractive possibility, the details of such an approach remain largely unspecified at this time. A full-fledged platform as envisioned for the long term requires specificity concerning the types and extent of services and transactions, which are largely absent for the grid at this time. A more likely near-term, evolutionary case for utilities may be an ecosystem designed around a scaled-down version of the platform model. A more incremental approach might focus first on leveraging distributed energy management systems (DERMS) and advanced metering infrastructure, including the attendant communication network, to facilitate more customer benefits, such as the increased use of innovative energy efficiency and advanced DR applications.[38]

Ultimately, some degree of change to the traditional model will likely be required in the near term to ensure that utilities remain viable and fulfill a meaningful role going forward. A modern regulatory framework should be cognizant of the evolutionary trends already underway. The current transition in Hawaii will require changes to regulations that preserve sufficient future flexibility and, in some cases, help to facilitate the advancement of platform utility features.

8 Next Steps

The purpose of this concept paper is to facilitate efficient progress towards the remaining objectives in Phase 1 of this proceeding, principally including: (1) evaluation and identification of which regulatory mechanisms are best-suited for changes to address the identified desired outcomes; and (2) identifying, metrics, where appropriate, to measure the utility's performance in achieving identified outcomes.

The remaining procedural steps for this stage of Phase 1 of the PBR proceeding include Technical Workshop #3 and the Parties' subsequent Metrics briefs.

Technical Workshop #3

To be held on Wednesday, November 28, Technical Workshop #3 will include collaborative activities to explore a common approach and set of principles to guide metric design and to consider new regulatory approaches or refinements to existing approaches to best achieve prioritized outcomes.

[38] *See, generally* Brattle Report at 9-10.

Metrics Briefs

Due January 4, 2019, the Parties shall submit briefs that focus on mapping prioritized regulatory outcomes to appropriate regulatory mechanisms as well as proposing specific metrics for each outcome, where appropriate. More specifically, Parties may consider structuring their briefs to include the following:

■ Map each priority outcome to the relevant category of regulatory mechanisms as illustrated in Section 6 of this report;

■ Propose input on a common set of metrics principles and set forth proposed metric(s), where appropriate, for each of the outcomes for further focus in Phase 2; and

■ Propose and provide insight on refinements to current mechanisms or the creation of other potential mechanisms to best achieve the list of prioritized outcomes.

APPENDIX A

Metrics Identified in Other Jurisdictions

Appendix A

Metrics Identified in Other Jurisdictions

This appendix provides a review of metrics that are either applied or in development in other jurisdictions, which can provide a helpful reference for available approaches and applications as Hawaii pursues further metric development.

New York's Reforming the Vision (REV) Initiative

In the New York Public Service Commission's (NYPSC) Track 2 Order in the Reforming the Energy Vision (REV) proceeding,[1] the commission identified certain areas of performance it wanted the utility to track. These included:

- System efficiency
- Energy efficiency
- Customer engagement
- Interconnection
- Affordability
- Clean energy standard compliance

Performance metrics were to be included either in a public-facing scorecard or developed into a PIM (New York calls these earnings adjustment mechanisms [EAMs]). The NYPSC opted to define those metrics that were to be made into incentive mechanisms for each of the state's investor-owned utilities as part of their next general rate case proceeding. For those metrics without a monetary reward, a working group was convened at each utility to develop the requisite set of scorecard metrics using a collaborative stakeholder process.

[1] CASE 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. *Order Adopting a Ratemaking and Revenue Model Policy Framework*. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BD6EC8F0B-6141-4A82-A857-B79CF0A71BF0%7D;

An overview of the metrics used for EAMS by one New York utility, National Grid,[2] and the Track 2 Order's scorecard metrics is included in Table 1.

Table 1: Overview of Metrics for Scorecard and Earnings Adjustment Mechanisms in New York's REV Proceeding

Category	Metric	Description	Calculation	Scorecard	Incentive Mechanism
System Efficiency	System utilization & efficiency	Encompasses load factor, transmission and distribution (T&D) system utilization, fuel diversity, and overall system rate		X	
	Peak reduction	Weather-normalized coincident transmission system peak demand	Sum of: • The weather-normalized demand on National Grid's system during the New York Control Area (NYCA) peak hour, plus • Any amounts of actually curtailed contracted DR resources enrolled in the New York Independent System Operator's (NYISO) Installed Capacity – Special Case Resource program during the NYCA peak hour		X
	DER penetration	Focus on the penetration of distributed generation, dynamic load management, and energy efficiency as a percentage of total utility load		X	
	DER utilization	Sum total of annualized MWh from incremental DERs (solar PV, CHP, Fuel Cell, battery storage)	Sum total of annualized MWh from incremental DER in National Grid's service territory as follows: • Community and Rooftop Solar PV production (MW installed x 13.4% capacity factor x hours/year)		X

[2] CASE 17-E-0238, et al. – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service. *Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans*. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={5CD14472-802C-4E01-9165-1A15C6B6E279}

Category	Metric	Description	Calculation	Scorecard	Incentive Mechanism
			• Combined heat and power production (MW installed x 85% capacity factor x hours/year) • Fuel cell production (MW installed x 91% capacity factor x hours/year) • Battery storage discharge (Daily battery inverter MWh discharge rating x 365 days/year) • Battery storage charge (Daily batter inverter MWh discharge rating x 365 days/year/83% round trip efficiency)		
Customer Engagement	TOU rate efficacy	Rate of adoption of opt-in TOU rates, and the ability of customers to reduce their bills via these rates		X	
	Customer satisfaction	Utilize existing indices that measure customer satisfaction, complaint response time, escalated complaint response time, and pending cases		X	
	Customer enhancement	Broader index encompassing the affordability metric, customer engagement in markets, customer satisfaction, and Home Energy Fair Practices Act (HEFPA) compliance rates		X	
	Affordability	Promotion of low-income customer participation in DER, and progress in reducing terminations and arrearages		X	
Interconnection		Utility progress in timely and cost-effective interconnection	Measured as part of a developer satisfaction survey, with specific targets to be set in a subsequent proceeding (Case 16-M-0429)		X

Category	Metric	Description	Calculation	Scorecard	Incentive Mechanism
		approvals measured via surveys of DER providers			
Clean Energy Standard	Carbon reduction	Track the market penetration of carbon-free sources as a percentage of total load within each utility's service territory		X	
	Conversion of fossil-fueled end-uses	Track the adoption rates of electric vehicles and conversion of combustion appliances to high-efficiency electric appliances		X	
	Beneficial electrification	Uptake of electric vehicles and electric heat pumps	Measured as the lifetime metric tons of avoided carbon dioxide from incremental electric vehicles and heat pumps compared to regional penetration levels		X
Energy Efficiency	Incremental savings	Sum total of annual MWh from all utility-administered energy efficiency programs	Annual sum of MWh savings from all of National Grid's administered energy efficiency programs		X
	LED street lighting conversion	Number of street lights converted to LED technology	MWh saved as generally established using a percentage of street light conversions each year		X
	Residential energy intensity	Year-over-year percentage change in weather-normalized per-customer electricity usage	Year-over-year percentage change in weather normalized annual kWh usage for residential customer class divided by the 12-month average number of customers in the residential customer class, adjusted to exclude the impacts of beneficial electrification		X
	Commercial energy intensity	Year-over-year percentage change in weather-normalized per-customer electricity usage	Year-over-year percentage change in weather normalized annual kWh usage for commercial customer class divided by the 12-month average number of customers in the commercial customer class, adjusted to exclude the impacts of beneficial electrification		X
Market Development	Distributed system platform	Track the standard indicators of market health including		X	

Category	Metric	Description	Calculation	Scorecard	Incentive Mechanism
	(DSP) market development	transparency, ease of access, settlement facilities, and dispute resolution			
	DSP market-based revenues	Track the amount, and sources, of utility revenues from distribution system platform and value-added services, to reflect the degree of market uptake and the success of utilities in adjusting their business models		X	

Rhode Island's Power Sector Transformation Initiative

The Phase One report in Rhode Island's Power Sector Transformation initiative focused on a need to shift utility regulation towards a "pay-for-performance" model through the development of incentive mechanisms that would promote specific outcomes aligned with public policy goals. The three areas identified were:

- System efficiency
- Distributed energy resources
- Customer and network support

Each category as well as specific metrics within that category were described in the report.

National Grid, the investor-owned utility in Rhode Island, proposed a smaller set of metrics in its most recent rate case. The Public Utilities Commission approved an amended settlement that reduced the list of metrics further for this initial performance-based regulation effort. Table 2 provides an overview of the one metric chosen for PIM development and the metrics established for scorecard reporting (and potential incentive mechanisms in some cases) in National Grid's amended settlement agreement filed in its most recent rate case proceeding.[3]

[3] National Grid's Amended Settlement Agreement in Docket Nos. 4770 and 4780, August 10, 2018. pp.75-91. http://www.ripuc.org/eventsactions/docket/4770-4780-NGrid-AmendedSettlement(Redlined)_8-10-18.pdf

Table 2: Metrics included in National Grid's Amended Settlement Agreement (August 10, 2018)

Category	Metric	Description	Calculation	Scorecard	Incentive Mechanism
System Efficiency	Annual MW capacity savings	The proposed list of eligible resources for Annual MW Capacity Savings includes: ▪ Demand Response, which will not be eligible for an incentive under RI's existing energy efficiency shareholder incentive; ▪ Incremental net-metered behind-the-meter PV distributed generation in excess of National Grid's forecast levels; ▪ Incremental installed energy storage capacity ▪ Any additional actions that National Grid identifies to reduce peak demand, including non-wires alternatives expected to influence system peak that are not captured already under this or other metrics, and partnerships with third parties to provide peak reduction solutions			X
DERs	Installed energy storage capacity	National Grid will track incremental installed energy storage capacity		X	
	CO2: electric vehicles	Incremental avoided tons of CO2 resulting from National Grid's proposed Electric Transportation Initiative. National Grid's forecast was	National Grid will track and report performance by (1) calculating incremental vehicles above National Grid's forecasts; (2) calculating the	X	The PUC will evaluate whether to allow a

Category	Metric	Description	Calculation	Scorecard	Incentive Mechanism
		developed by applying a growth rate in EV sales for 2018 through 2021 derived from the Energy Information Administration's Annual Energy Outlook 2018 projection of EV sales in New England, to historic data on EV registrations in Rhode Island from R.L. Polk.	number of incremental Battery Electric Vehicles (BEVs) and Plug-in Hybrid Electric Vehicles (PHEVs) by multiplying the total number of incremental vehicles by the share of all new registrations that were BEVs, and the share of all new registrations that were PHEVs; and (3) applying per vehicle annual CO2 emissions reduction values as follows: • Incremental BEVs x 2.32 metric tons CO2 • Incremental PHEVs x 2.08 metric tons CO2		financial performance incentive for this metric prior to Rate Year 2.
	Light duty government and commercial fleet electrification	Intended to capture the impact of National Grid's electric transportation initiative on light-duty fleet adoption in Rhode Island relative to predicted market trends. The metric will measure incremental increase – above predicted levels – of government and commercial light-duty fleet electric vehicles in the state on an annual basis.	National Grid will track and report the incremental registrations (both in total and above National Grid's forecast based on R.L. Polk data or an acceptable substitute should the Polk data become unavailable.	X	The PUC will evaluate whether to allow a financial performance incentive for this metric prior to Rate Year 2.
Power Sector Transformation Enablement	Activated Low-income and Multi-unit Electric Vehicle Supply Equipment (EVSE) Sites	This metric will track EVSE sites for apartment buildings and disadvantaged communities.	National Grid will report the in-service date for make-ready work and charging stations installed in both site categories.	X	
	DG interconnection – time to interconnection service agreement (ISA)	National Grid will track its performance for the simplified, expedited without supplemental review, and standard tracks in meeting or outperforming tariff timelines for providing an	Calculated by: ▪ Aggregating the average time measured in Business Days necessary to issue an executable Interconnection Service Agreement commencing	X	

Category	Metric	Description	Calculation	Scorecard	Incentive Mechanism
		executable interconnection service agreement.	from the date an application is received, for each track identified above (Aggregate Necessary Tariff Time Frames), and comparing such performance to ▪ The total aggregate number of Business Days allowed by its Interconnection Tariff to issue an executable Interconnection Service Agreement commencing from the date an application is received (Aggregate Allowed Tariff Time Frames).		
Scorecard metrics that were not categorized	Distributed Generation (DG) interconnections	Will track the number of business days from executed ISA to distribution system modifications by category of interconnection (i.e., simple, expedited, standard).	For each category, National Grid will calculate and report the averages and the variances from the averages.	X	
	DG-friendly substation transformers	Will base reporting on the number of incremental 3VO installations completed		X	
	Utilization of EVSE in low-income area	Utilization rates at all EVSE sites installed through the Charging Station Demonstration Program		X	
	Non-regulated power producers (NPP) residential customer demand response participation	Measures the number of NPP residential customers participating in the National Grid's Connected Solution program or any future demand response program that works with WiFi-enabled or smart thermostat(s) and other connected smart devices to reduce electricity use during periods of high energy demand.		X	

Category	Metric	Description	Calculation	Scorecard	Incentive Mechanism
	Reduction of uncollectable debt	Enrollment in the Arrearage Management Plan (AMP) at the point of potential termination from service for purposes of developing a baseline and eventually setting an improvement target from this baseline, to maintain service to the low-income customer and prevent expansion of uncollectible debt.		X	
	Increased stability of service through increased enrollment in the low-income discount	Enrollment in the low-income discount, represented by number of customers receiving delivery service on Rate A-60 for the purposes of developing a baseline and eventually setting an enrollment target that improves upon the baseline.		X	

United Kingdom's Revenue = Incentives + Innovation + Outputs (RIIO) Initiative

In October 2010, the utility regulator in the United Kingdom, the Office of Gas and Electricity Markets (OFGEM), issued an order that sought to fundamentally reformulate the way that electric (and gas) utilities were regulated. The general output categories identified in the decision were:

- Reliability and availability
- Environmental impact
- Conditions for connection
- Customer satisfaction
- Social obligations
- Safety

These broad categories were then broken down into sets of metrics. Table 3 lists the metrics established for the distribution electric utilities and identifies whether the metric was intended to be reported on a scorecard and/or tied to a financial incentive mechanism.[4]

Table 3: Metrics included in the UK RIIO Initiative for Distribution Electric Utilities

Category	Metric	Description	Calculation	Scorecard	Incentive Mechanism
Reliability and Availability	Interruption incentive scheme	Number and length of network supply interruptions	Planned and unplanned customer interruptions (frequency) and customer minutes lost (duration)	X	X
	Guaranteed standards of performance	Deliver specified minimum levels of performance regarding interruptions	Combination of frequency and duration of outages based on the cause of the outage	X	X
	Worst-served customers	Improve reliability for a subset of customer whose supply has been repeatedly interrupted	Service improvement (percentage reduction in power cuts) to those customers who have significantly worse than average service	X	X
	Health, criticality, and monetized risk	Obligation to reduce the risk of network assets failing	Health – a composite of a number of parameters, including asset age, condition, fault history, and probability of failure Criticality – Composite of network performance, environmental, safety, and financial consequences of an asset failing Risk – Combines scores of the Heath index and Criticality metrics to calculate value of monetized risk on each utility's network		X
	Load index	Obligation to reduce the risk of network overloading	Measured as the loading of the primary network's substations	This metric was only established to inform other procedural matters.	
	Network Resilience	Induce investment to reduce impact of disruptive events	No actual metric is used but a budget is provided for investment to make the system more resilient	X	

[4] Guide to the RIIO-ED1 electricity distribution price control. pp.28-67. https://www.ofgem.gov.uk/system/files/docs/2017/01/guide_to_riioed1.pdf

Category	Metric	Description	Calculation	Scorecard	Incentive Mechanism
Environment	Electricity network losses	Obligation to manage network energy losses	Measured as the difference between metered load at the generation bus and the metered load at the customer meter	X	X
	Business carbon footprint	Induce reduction in the operating company's carbon footprint	Measured as the carbon emissions from the utility's operations including direct emissions sources and indirect sources from the activities of the organization	X	
	SF_6 emissions	Limit emissions of sulfur hexafluoride	Amount of SF_6 emissions that come from its use in high voltage circuit breakers, switchgear, and other electrical equipment as an insulator	X	
	Cable leakage	Limit leakage from fluid-filled electric cables	Volume of oil-based fluids on certain cables that was topped off	X	
	Noise pollution	Limit noise pollution	Number of noise complaints from transformers at substations	X	
	Undergrounding of distribution lines	Reduce visual impact by undergrounding overhead lines in areas of outstanding natural beauty and national parks	Length of the overhead lines removed and length of underground lines installed	X	
	Reporting on environmental mitigation activities	Inform stakeholders about activities undertaken in relation to environmental matters, including their role in transition to a low carbon economy		X	
Connections	Time to connect	Induce reduction in time taken to connect smaller and less complex customers systems	Time taken to develop an estimate for the connection and time taken to actually make the connection for smaller and less complex DER systems		X
	Connections engagement	Effectively engage with customers seeking larger and more complex system connections and help them understand requirements	Comparison of a "Looking Forward" report at the beginning of the year, presenting the utility's strategy for engagement, work plan of activities, and key performance outputs for the coming year, and "Looking Backward" report at the end of the year, presenting the utility's evaluation of their performance		X

Category	Metric	Description	Calculation	Scorecard	Incentive Mechanism
	Guaranteed standards of performance (GSoP)	Deliver specified minimum levels of performance regarding connections	Number of cases where the GSoP standard applies and met vs. not met.	X	X
Customer Service	Customer satisfaction	Survey connected, interrupted, and general customers	Customer satisfaction survey of who have made a general inquiry, experienced an interruption, or required a connection		X
	Complaints	Improve customer satisfaction related to complaint handling procedures	Measures the effectiveness of the utility in resolving complaints		X
Social Obligations	Stakeholder engagement and customer vulnerability	Induce strong engagement with all stakeholders and address customer vulnerability issues	Level of stakeholder engagement and customer vulnerabilities activities		X
Safety	Safety compliance	Drive compliance with statutory requirements in Health and Safety Executive	Utilities are obligated to maintain compliance with statutory regulations to ensure their equipment is safe and protected, and that the public are aware of any dangers. They are also subject to general health and safety legislation. These are enforced and regulated by the Health Safety Executive.		X
	Asset health and criticality	Maintain health of critical assets			X

Ontario Power Distributors' Performance Categorizes Measures

Power distributors in Ontario are regulated by the Ontario Energy Board. Each year, the 66 distributors report their performance against 23 measures, as listed below.[5] Rather than a goals-outcomes-metrics hierarchy, Ontario uses a "performance outcomes – performance categories – measures" structure, with a comprehensive scorecard available online to track performance against

[5] Ontario Energy Board Scorecard – Performance Measure Descriptions. https://www.oeb.ca/oeb/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

measures. For some measures, each utility may report using different methods. Table 4 describes the performance measures tracked in Ontario.

Table 4: Ontario Power Distributors' Performance Measures

Performance Outcomes	Performance Categories	Measures	Description
Customer Focus	Service Quality	New residential/small business services connected on time	The utility must connect new service for the customer within five business days, 90% of the time, unless the customer agrees to a later date. This timeline depends on the customer meeting specific requirements ahead of time (such as no electrical safety concerns in the building, customer's payment information complete, etc.)
		Scheduled appointments met on time	For appointments during the utility's regular business hours, the utility must offer a window of time that is not more than four hours long, and must arrive within that window, 90% of the time.
		Telephone calls answered on time	During regular call center hours, the utility's call center staff must answer phone calls within 30 seconds of receiving the call directly or of having the call transferred to them, 65% of the time.
	Customer Satisfaction	First contact resolution	Utilities should aim to address their customers' needs as quickly as possible. Ideally, their concerns and issues can be resolved the first time the customer contacts the utility. The utility must report on its success at meeting a customer's needs the first time the utility is contacted. Different tools can be used to measure this.
		Billing accuracy	An important part of business is ensuring that customer's bills are accurate. The utility must report on its success at issuing accurate bills to its customers.
		Customer satisfaction survey results	Utilities use different ways to determine how satisfied their customers are with the service they receive. The utility must report the results of whatever customer satisfaction surveys it uses.
Operational Effectiveness	Safety	Level of public awareness	The equipment used to run the electricity system is extremely dangerous. Because equipment such as power lines and poles can be located in public areas, the

Performance Outcomes	Performance Categories	Measures	Description
			utility must take steps to prevent electrical accidents or incidents involving the public. One way is to provide information about safety risks and precautions to take when near this equipment. Starting in 2015, the utility will carry out a survey every two years that measures the effort made to raise the public's awareness about these risks. The Electrical Safety Authority will develop the survey.
		Level of compliance with Ontario Regulation 22/04	Ontario Regulation 22/04 – Electrical Distribution Safety sets out safety standards that utilities must follow in their operations. The utility must demonstrate how well it met the standards by providing declarations, audit results, inspection reports and other documentation.
		Serious electrical incident index: Number of general public incidents	The utility must report on any serious electrical incidents involving its equipment and the general public. A 'serious electrical incident' means either any electrical contact that caused death or critical injury to a person; any inadvertent contact with any part of a distribution system operating at 750 volts or above that caused, or had the potential to cause, death or critical injury to a person; or any fire or explosion in any part of a distribution system operating at or above 750 volts that caused, or had the potential to cause, death or critical injury to a person, except a fire or explosion caused by lightning strike.
		Serious electrical incident index: Rate per 10, 100, 1000 km of line	
	System Reliability	Average number of hours power to customer is interrupted	An important feature of a reliable distribution system is recovering from power outages as quickly as possible. The utility must track the average length of time, in hours, that its customers have experienced a power outage over the past year.
		Average number of times power to customer is interrupted	Another important feature of a reliable distribution system is reducing the frequency of power outages. The utility must also track the number of times its customers have experienced a power outage over the past year.

Performance Outcomes	**Performance Categories**	**Measures**	**Description**
	Asset Management	Distribution System Plan implementation progress	Utilities use different ways to determine that their work continues to be “on track” with their system plans. The utility must report the results of whatever measure it uses.
	Cost Control	Efficiency assessment	The utility must manage its costs successfully in order to help assure its customers they are receiving value for the cost of the service they receive. Utilities’ total costs are evaluated to produce a single efficiency ranking. This is divided into five groups based on how big the difference is between each utility’s actual and predicted costs. Utilities whose actual costs are lower than predicted are considered more efficient.
		Total cost per customer	Total cost is a sum of all the costs incurred by the utility to provide service to its customers. The amount is then divided by the utility’s total number of customers.
		Total cost per km of line	Total cost is a sum of all the costs incurred by the utility to provide service to its customers. The amount is then divided by the number of kilometers of line the utility operates to serve its customers.
Public Policy Responsiveness	Conservation & Demand Management	Net cumulative energy savings	Customers can reduce the amount of power they use through conservation efforts, as progress towards the conservation goals set out by the Minister of Energy in 2014.
	Connection of Renewable Generation	Renewable generation connection impact assessments completed on time	The utility must complete a connection impact assessment for a renewable generator within a certain timeline, and must report to the Board on how well it met those timelines.
		New micro-embedded generation facilities connected on time	The utility must connect smaller generators producing less than 10kW of power within five business days, 90 percent of the time, unless the customer agrees to a later date. These generators are known as “micro-embedded generation facilities.” The timeline depends on the customer meeting specific requirements ahead of time.

Performance Outcomes	Performance Categories	Measures	Description
Financial Performance	Financial Ratios	Liquidity: current ratio	This first ratio measures whether or not the utility has enough resources (assets) to pay its debts (liabilities) over the next 12 months.
		Leverage: total debt to equity ratio	This measures the degree to which the utility is leveraging itself through its use of borrowed money.
		Profitability: regulatory return on equity – deemed	Return on Equity is the rate of return that the utility is allowed to earn through its distribution rates, as approved by the Ontario Energy Board.
		Profitability: regulatory return on equity – achieved	This measure shows the utility's actual Return on Equity earned each year.

APPENDIX B

Summary of Parties' Regulatory Assessment Briefs

Appendix B

Summary of Parties' Regulatory Assessment Briefs

In their Regulatory Assessment Briefs, Parties were encouraged to perform an assessment for each of their top five priority outcomes and how existing regulatory mechanisms impact the achievement of outcomes. To aid the Parties in conducting their assessments, Staff's second concept paper included a suggested structure to evaluate individual regulatory mechanisms' efficacy in supporting the achievement of identified outcomes and characterize inter-dependencies and tradeoffs between outcomes and mechanisms.

The following Parties submitted Regulatory Assessment Briefs: Division of Consumer Advocacy ("CA"); Hawaiian Electric Companies ("HECO"); County of Maui; City and County of Honolulu; County of Hawaii ("COH"); Ulupono Initiative, LLC ("Ulupono"); Life of the Land ("LOL"); Blue Planet Foundation ("Blue Planet"); and Hawaii Coalition, Hawaii Solar Energy Association and Distributed Energy Resources Council of Hawaii ("DER Intervenors").

The Parties submitted detailed and thoughtful feedback on the relationship between existing regulatory mechanisms and potential PBR outcomes during Technical Workshop #2 and through their respective briefs. From the feedback provided to date, several themes have emerged. While many of the Parties provide similar feedback on whether regulatory mechanisms incent or disincentivize achievement of certain outcomes, Parties also make conclusions about the existing regulatory framework that significantly diverge from the findings of other Parties.

A majority of the Parties find the current regulatory model encourages capital spending by the utility as a way of securing utility financial integrity even if it hinders desired goals and outcomes.[1] Some Parties discuss how they find the current regulatory framework to be outdated and inherently flawed as it is not supportive of operational efficiency and fosters a capital bias effect.[2] Some Parties agree that current regulatory mechanisms are merely incremental adjustments to mitigate, but not fully remediate, innate fundamental flaws of the regulatory framework.[3] Other Parties discuss how the existing regulatory framework has succeeded in generally providing good levels of reliability, power quality, and safety, preserving financial integrity, and contains certain elements that are supportive of transformational change and that should be continued and improved with certain modifications.[4]

Several Parties believe that PBR should transform the regulatory model so that it discourages utility-capital bias and fosters a more market-based service model that prioritizes outcomes such as cost control, investment efficiency, DER asset effectiveness, social equity, resilience, reducing

[1] See for example: COH at PDF pages 8, 35, and 46; "DER Intervenors" at PDF pages 3, 5, 7, 9; Ulupono at PDF pages 17, 18, 20, 22, 27, 35; CA at PDF pages 11, 56, 77, 79,

[2] See for example: Ulupono at PDF pages 17, 18, 20, 22, 27, 35; "DER Intervenors" at PDF pages 3, 5, 7, 9; CA at PDF pages 11, 56, 70

[3] See for example: "DER Intervenors" at PDF pages 4, 5; Ulupono at 3,

[4] See for example: Ulupono at 14, 45; HECO at PDF pages 3, 90, 137, 139; CA at PDF pages 9, 70.

greenhouse gas emissions, and ensuring capital formation at all levels.[5] Some parties recommend the development of more targeted and well-calibrated incentives but caution that there is substantial risk associated with creating new or significantly modifying revenue adjustment mechanisms with parameters that may not be accurately specified.[6] Parties also warn about the risks associated with designing new mechanisms including unintended consequences, excessive complexity, information asymmetry, free-ridership, and creating metrics that may be at cross-purposes.[7]

There is a need to continue thoughtful dialogue around what will make up the appropriate outcomes, understand the existing regulatory framework, and to guide the proceeding and sufficiently focus efforts in Phase 2. The following summary of the Parties' Regulatory Assessment Briefs is offered to help advance the conversation.

Multi-Year Rate Plan

Many of the Parties note how the triennial rate cases have important interdependences with other elements of the existing regulatory framework. The CA discusses how rate cases are used to determine RAM inputs, the interest rate applied to RBA balances, ECAC heat rates, cost deferral rate recovery and amortization, and cost allocation and rate design.[8] Accordingly, rate cases are an important venue for proposed changes to major mechanisms in the regulatory framework.[9]

While the CA believes that triennial rate cases provide improved financial stability and increased cost recovery certainty for the utility,[10] HECO maintains that the MYRP, alone, does not promote financial stability and that without sufficient interim recovery mechanisms the Company would not be able to earn its authorized returns.[11] Parties including the CA and the City and County of Honolulu suggest that extended rate case intervals could reduce administrative burden and complexity.[12] HECO believes that extending the "stay-out" period of the MYRP is undesirable unless the utility can reasonably recover prudently incurred costs in-between rate cases and states that longer stay-out periods can lead to low returns.[13]

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[5] See for example: COH at PDF pages 3, 8, 35, and 46; Maui County at PDF pages; Blue Planet at PDF pages 2, 4, 5; "DER Intervenors" at PDF pages 3, 4, 5, 7, 9; Ulupono at 2, 3, 17, 18, 20, 22, 27, 35; CA at PDF pages 5, 11, 56, 70-73; Life of the Land at PDF pages 14-15.

[6] See for example: CA at PDF pages 34, 37, 40, 50, 70, 79, 86; Ulupono at PDF pages 11, 20, 21

[7] See for example: Ulupono at PDF pages 11, 20, 21; CA at PDF pages 21, 34, 37, 39, 40, 41, 48, 50, 70, 71, 72, 79, 86

[8] See CA Brief at 8.

[9] Id.

[10] See CA Brief at 9.

[11] See HECO Exhibit 5 at 1.

[12] See CA Brief at 15. See Also C&C Honolulu Brief at 2.

[13] See HECO Exhibit 5 at 2.

The CA maintains that there is a relative absence of cost-control incentives in rate cases besides the passive cost control incentive caused by regulatory lag and prudence disallowances.[14] However, the CA notes that prudence investigation proceedings and cost disallowances by utility regulators are "rarely undertaken and completed."[15] The CA mentions how the RAM dilutes the regulatory lag cost control incentive.[16]

The CA states that MYRPs do not promote cost control as "higher costs are rewarded with higher rates."[17] Other parties including Blue Planet, Ulupono, County of Hawaii, similarly explain how the existing regulatory framework does not promote cost control as there is an inherent structural bias or a "capital bias effect" that encourages the utility to overinvest in capital.[18]

The CA emphasizes that the cost of service approach and future test year used in rate cases have caused "inherent bias and asymmetrical information access problems… because most of the cost inputs are management's estimates that must be analyzed and rigorously tested."[19] The CA argues that depending on forecasts rather than actual utility cost data in rate cases "provides an incentive for management to construct pessimistic forecasts to justify larger rate increases."[20] However, the CA acknowledges that rate cases and cost of service regulation support the utility's service quality programs and initiatives such as grid modernization by providing an opportunity for utilities to fully recover reasonable costs incurred.[21]

The DER Interveners state that the three-year term for multi-year rate plans "may be inadequate to maximize confidence in the longer-term investments" and that "the years between rate cases may prolong some problems [by] deferring their resolution until the next major rate case."[22] As a result, the DER Interveners explain how "core utility financial issues are often the dominant issues, and relatively small capital investments, rate changes, and other issues may not receive the attention or engagement they deserve."[23]

HECO maintains that the MYRP may disincentivize achievement of the following outcomes because the costs may not adequately be recovered between rate cases: RPS Achievement, DER Effectiveness, Capital Formation, potentially the implementation of HECO's Grid Modernization Strategy, and Interconnection Experience for CBRE.[24] The County of Hawaii also suggests that the three-year rate case cycle could "stymie HECO's ability to seek rate recovery on backbone

[14] See CA Brief at 13.
[15] CA Brief at 12.
[16] See CA Brief at 13.
[17] CA Brief at 14.
[18] See for Example Blue Planet Brief at PDF p. 6, Ulupono Brief at 17, County of Hawaii Brief at PDF p. 16.
[19] CA Brief at 11 and 12.
[20] CA Brief at 12-13.
[21] See CA Brief at 14.
[22] DER Intervenors' Brief at 8.
[23] Id.
[24] See HECO Exhibit 3 at 1, Exhibit 4 at 2, Exhibit 5 at 1, Exhibit 6 at 1, Exhibit 7 at 29.

infrastructure needed to progress EoT."[25] The County of Hawaii does however acknowledge that MYRP "assists EoT by allowing the utility time to implement EoT pilots, and time to hone and tweak those pilots without interruption by a time intensive rate case every year."[26]

Regulatory Adjustment Mechanism (RAM)

Several Parties provide an in-depth discussion on the benefits and drawbacks of the RAM and offered suggestions for how this mechanism could be improved. Parties including the CA and HECO express that one of the most important benefits of the RAM is that it supports stable earnings and capital access for the utility.[27] The CA states that without the RAM, "it is unlikely that the utilities would elect to file rate cases only every three years."[28]

Parties including the CA, Ulupono, and the County of Hawaii, maintain that one of the main drawbacks of the RAM is that it does not promote cost control or affordability as RAM adjustments produce additional upward pressure on energy prices through annual filings and target revenue increases.[29] The City and County of Honolulu explains how RAM investment decisions don't internalize external societal and environmental costs and that it may provide an "escape hatch" for bad planning.[30] The City and County states that "Effective grid planning should alleviate the need to reset Target Revenues or seek extraordinary recovery."[31] The City and County suggests that the commission should assess whether investments recovered through the RAM are in line with the state's renewable energy goals, climate change adaptation, resilience, and carbon reduction.[32] Similarly, Blue Planet recommends that cost recovery mechanisms for generation infrastructure should avoid any bias for prolonging reliance on fossil fuels.[33] Ulupono suggests that the RAM "invites gaming" and "may contribute to competitive market share erosion."[34]

In contrast, HECO states that because the RAM provides less than full recovery, there is an incentive to contain costs. More specifically, HECO explains how the RAM has

> "no provision to include expenses or deferred costs for new programs and requirements above test year expenses, there is no escalation of management labor costs, bargaining unit labor increases are based on the wage rate increases in the BU contract but is subject

[25] COH Brief at PDF p. 49.
[26] Id.
[27] CA Brief at 17; HECO Brief at 7
[28] CA Brief at 17.
[29] See CA Brief at 17, Ulupono Brief at 20, COH Brief at PDF p. 40.
[30] See C&C Honolulu Brief at Appendix A at 10.
[31] C&C Honolulu Brief at PDF p. 16.
[32] Id.
[33] Blue Planet at PDF p. 6.
[34] Ulupono Brief at 31.

to a productivity factor, major projects must be scheduled for completion by Sept 30 of the RAM period, [and] baseline plant adds based on 5-year average."[35]

HECO argues that because the accrual and collection of RAM revenues are lagged by five months, the achievement of authorized returns is hindered.[36]

The DER Intervenors recommends that the Commission should evaluate ending the RAM and claims that it may "dampen the incentive for better forecasting and weaken the incentive for the utility to develop a more robust business model that is not so subject to exogenous conditions."[37] The DER Intervenors argue that the RAM "can have the effect of weakening the value proposition for DERs by automatically increasing revenue requirements in step with inflation."[38]

Blue Planet maintains that the RAM "encourage[s] a bias in favor of utility investment rather than opex spending to support DERs."[39] Blue Planet suggests that the RAM "could be modified to remove distinction between Capex and Opex, reducing bias against DERs. Further, the two RAM caps could be merged into a single cap along the lines of GDPPI minus X for allowed revenue levels between rate cases."[40] Contrary to Blue Planet, the County of Hawaii states that the "RAM arguably provides a financial incentive, or at least reduces the disincentive, for the Companies' participation in DERs and to provide new rate plans, and provide data, to third party energy providers."[41]

HECO discusses how the RAM provides the utility baseline capital needed to advance RPS, allows recovery to support grid modernization efforts and therefore promotes DER Asset Effectiveness, and facilitates the timely recovery of costs are critical to maintaining and improving the Company's financial health and credit quality.[42] Similarly, Maui County states that the RAM is an effective way to pay for infrastructure needed to maintain resilience between rate cases.[43]

The CA recommends that any reconsideration of the RAM should avoid adding layers of new complexity to the existing mechanism.[44] The CA states that any modifications to the RAM could consider "relying directly upon external price level indices to replace all or most of the traditional RAM, allowing outside the index adjustments only for carefully defined exogenous changes."[45]

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[35] HECO Brief Exhibit 2 at 3.
[36] Id.
[37] DER Intervenors Brief at 8.
[38] Id.
[39] Blue Planet Brief at PDF p. 15.
[40] Id.
[41] COH Brief at PDF p. 16.
[42] See HECO Brief Exhibit 2 at 2, Exhibit 3 at 2, Exhibit 4 at 3, Exhibit 5 at 3.
[43] See Maui County Brief at 16.
[44] CA Brief at 18.
[45] CA Brief at 18.

Parties assigned a neutral score to the RAM for promoting the outcomes of grid planning effectiveness, customer engagement, cost-effective system operations, reducing carbon intensity, and EoT.

RAM Cap

Many parties including the CA, the County of Hawaii, HECO, discuss how the RAM Cap has been supportive of the affordability outcome by limiting the size of target revenue increases approved through annual RAM filings.[46] HECO states that from 2015-2018, the RAM Cap has resulted in an average decrease in RAM revenues of $14.3 million per RAM Period for Hawaiian Electric.[47] Other parties including the City and County of Honolulu and Maui County state that the RAM Cap does not seem to impact the achievement of the Cost Control or Affordability outcomes.

Blue Planet asserts that the RAM Cap "does not eliminate the underlying bias in favor of utility capital investment."[48] Likewise, Ulupono maintains that "Incremental adjustments to RAM are inadequate solutions to the fundamental misalignment that results from the cost-plus utility model with achieving the goals and outcomes identified in this proceeding."[49] The City and County of Honolulu claims that the RAM Cap may disincentivize capital investments that reduce carbon.[50]

HECO states that the RAM Cap causes systematic under-recovery of needed investment and has a negative impact on its capital formation ability.[51] The CA makes a similar observation but points out that the "the cost control achieved by the utilities since the RAM Cap was installed have not harmed credit ratings and average achieved equity return levels are only modestly below Commission-authorized levels."[52]

The County of Hawaii observes that the RAM Cap may promote the outcome of resilience:

> "An indirect effect of the RAM Cap may help increase the influx of private capital to advanced distributed energy resources (DER), microgrids, or other consumer-side technologies that provide distributed generation as another resource for grid-level benefit."[53]

In contrast, Maui County finds that the RAM Cap may disincentive the achievement of the resilience outcome as it "may limit the recovery of investments that address resilience in between MYRPs."[54]

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[46] See for Example CA Brief at 20, COH Brief at PDF p. 16, and HECO Brief at 8.
[47] See HECO Brief Exhibit 2 at 9.
[48] Blue Planet Brief at PDF p. 16.
[49] Ulupono Brief at 9.
[50] C&C of Honolulu Brief Appendix A at 2.
[51] HECO Brief at 8.
[52] CA Brief at 21 and Attachment B.
[53] COH Brief at PDF p. 63.
[54] Maui County at PDF p. 27.

HECO argues that the RAM Cap is "insufficient to provide utility baseline capital investment needed to advance RPS."[55] HECO also states that because the capital expenditure recovery for the Grid Modernization Strategy is restricted in the RAM Cap, the outcome of DER Asset Effectiveness is hindered.[56] HECO contends that the RAM Cap disincentivizes the achievement of customer engagement in the CBRE program as it could limit capital investment needed to implement or interconnect CBRE projects.[57] Other parties give the RAM Cap a neutral score for customer empowerment and engagement and grid planning effectiveness.

The CA explains a potential drawback of the RAM Cap is that it has "potential to encourage cost control at levels that may compromise service quality and customers satisfaction outcomes."[58] The CA explains how the SAIDI and SAIFI backstop PIMS have mitigated this potential drawback. The CA points out how there are still no clear guidelines for "Above the RAM Cap" cost recovery.[59] The CA recommends that the RAM should be simplified:

> "[O]ne suggested direction for change would be to simplify the RAM by more complete reliance upon external inflation indices like the RAM Cap, in place of the complex and largely redundant traditional RAM calculations of rate base, O&M expense and depreciation and amortization updates each year…
>
> Movement toward an "index only" RAM would further this objective, by allowing the utilities to be rewarded for cost savings in every year when actual costs are managed at levels below the index, in contrast to the existing dual-track calculation that limits RAM recoveries to the lower of traditional RAM "cost" amounts or the index cap…
>
> [A]pplication of a cap should be based on a cumulative application of percentage indexing to discourage non-optimal shifting of expenditures from year to year as might result from discrete annual increments"[60]

HECO suggests that the "RAM Cap needs to be revised or possibly replaced with or enhanced by other incentive mechanisms to allow the Companies a fair opportunity to earn their authorized return."[61]

<u>Major Project Interim Recovery ("MPIR")</u>

The CA maintains that the MPIR is supportive of more robust resource and system planning efforts "by providing utility-built resource options an equally preferential cost recovery opportunity to purchased resources that are eligible for timely, full recovery through the Energy

[55] HECO Brief Exhibit 1 at 3.
[56] HECO Brief Exhibit 4 at 3.
[57] HECO Brief Exhibit 6 at 3.
[58] CA Brief at 21.
[59] CA Brief at 20.
[60] CA Brief at 21 and 22.
[61] HECO Brief at 8.

Cost Adjustment Clause ("ECAC") and Purchased Power Adjustment Clause ("PPAC")."[62] Blue Planet, Maui County, COH suggest that MPIR may support EoT initiatives

The CA, the City and County of Honolulu, Blue Planet, and County of Hawaii, maintain that the main drawback of the MPIR is that it disincentivizes the achievement of cost control.[63] County of Hawaii observes that MPIR is not subject to a cost ceiling and that this may encourage overuse by the utility.[64] In contrast, HECO claims that MPIR does promote cost control.[65]

The CA discusses how the MPIR represents single-issue or piecemeal ratemaking.[66] While there is a provision in the MPIR that only allows recovery of the "net benefits" of a project, the CA observes that it is "complicated and difficult to reasonably isolate and quantify" the savings and benefits enabled by the project.[67] The CA also states:

> "Limiting MPIR offsets to only the specific savings and benefits enabled by the project ignores potential efficiency savings achieved elsewhere in the business, such as the debt refinance savings."[68]

The City and County of Honolulu suggests that decision criteria for the identification of project benefits should include a more holistic benefit cost evaluation.[69] Similarly, Ulupono Initiative recommends that the MPIR "should be limited to capital investments that are proven optimal after full benefit-cost analysis, the thorough evaluation of non-utility solutions."[70] COH recommends that the MPIR should be used to incent project that specifically promote resilience.[71]

The City and County of Honolulu states that the MPIR is "anathema to third party procurements."[72] Blue Planet states that MPIR "reinforces traditional focus on utility investment."[73] Ulupono discusses how MPIR may encourage "a short-term perspective that could result in chasing short-term price-to-earnings financial metrics driven by remote shareholder and financial interests."[74]

Blue Planet states that MPIR may have a negative impact on the outcome of carbon intensity reduction if it provides any avenue for major investments in fossil fuel infrastructure. Blue Planet asserts that the MPIR "generally facilitates and reinforces the traditional focus on utility

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62 CA Brief at 25.
63 See CA Brief at 25, C&C of Honolulu Brief at PDF p. 20, Blue Planet Brief at PDF p. 16, and COH Brief at
64 COH Brief at 4.
65 HECO Brief Exhibit 2 at 4.
66 CA Brief at 26.
67 CA Brief at 26.
68 CA Brief at 26.
69 C&C of Honolulu Brief Appendix A at 6.
70 Ulupono Brief at 9.
71 COH Brief at PDF p. 63.
72 C&C of Honolulu Brief Appendix A at 14.
73 Blue Planet Brief at PDF p. 16.
74 Ulupono Brief at 9.

investment" thereby disincentives the achievement of maximizing optimization of DERs.[75] Likewise, Ulupono claims that in the absence of considering a "fully current benefit-cost analysis," MPIR may not consider the "rapidly improving economics of DERs will not be captured in the evaluation of the utility's proposed capital projects."[76] Similarly, the County of Hawaii argues that the MPIR disincentivizes the achievement of customer engagement around DERs, TOU programs, but does allow for utility scale renewables.[77] The County of Hawaii urges the Commission to "keep a close rein on the MPIR, which has in the past been utilized by HECO in ways that COH does not believe were intended by the Commission."

In contrast, HECO finds that the MPIR mechanism supports achieving the DER Asset Effectiveness outcome in particular since Grid Modernization Strategy investments are eligible for recovery under the MPIR. HECO argues that this also promotes RPS achievement.[78]

HECO states that the MPIR is neutral for grid planning effectiveness and can be viewed as both "positive and negative" for capital formation:

> "Application of the average rate base concept under MPIR results in the utility only being able to recover the return on investment for half of the project investment for the first year in service. For a major project, this can be a loss of a significant amount of recovery that the utility cannot recoup."[79]

HECO contends that MPIR could support the outcome of CBRE customer engagement "to the extent that CBRE capital and operational costs are eligible under MPIR."[80]

Certain parties find that the MPIR does not seem to impact the achievement of the following outcomes: carbon intensity, grid planning effectiveness, customer satisfaction, service quality, capital formation, and interconnection experience.

Revenue Decoupling: Revenue Balancing Account ("RBA")

Several of the Parties including the CA, City and County of Honolulu, Blue Planet, and COH observe that the RBA removes a short-term disincentive for utilities to encourage energy efficiency, DR, TOU, and DER initiatives that result in decreased sales volume. COH states that this could positively impact affordability for the customers that are able to opt into energy efficiency improvements.[81] The CA, COH, Ulupono, and HECO find that the RBA results in greater stability and creditworthiness for the utility as it lowers utility revenue risk.

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[75] Blue Planet Brief at PDF p. 16.
[76] Ulupono Brief at 9.
[77] COH Brief at PDF p. 16.
[78] HECO Brief Exhibit 4 at 3.
[79] HECO Brief Exhibit 5 at 4.
[80] HECO Brief Exhibit 6 at 3.
[81] Blue Planet Brief at PDF p. 30.

However, the DER Intervenors argue that revenue decoupling is a "classic example of a tool crafted to treat a symptom of the utility-capital bias problem without fully addressing the problem itself" and suggests that the Commission should consider the likelihood that such mechanisms actually create a bias in favor of utility capital investments.[82] Likewise, Blue Planet believes that the RBA does not address underlying capex bias in the long term.[83] Blue Planet states that while the RBA removes a direct, short-term barrier to DERS, "The beneficial effect of decoupling is purely 'defensive': it removes a barrier but does not provide a positive incentive for DERs."[84] The County of Hawaii maintains that revenue decoupling is less effective in incentivizing investment in cost-effective renewable energy because renewable energy sources are often lower cost than fossil fuel sources.[85] The DER Intervenors state that the RBA does not incentivize the utility to innovate and that "by keeping rates at the same level due to the upward RBA adjustment, system-wide economic benefit of the non-utility investments are reduced."[86]

Parties including the CA, COH, Blue Planet, and Ulupono find that one of the main drawbacks of the RBA is that it does not promote the affordability outcome since it as has persistently increased rates charged to consumers because of the steady decline in electric sales volumes. Ulupono observes that RBA mechanisms may increase rates to non-DER customers "as DER penetration increases competitive market share erosion when combined with COSR."[87] Blue Planets states that the RBA puts "upward pressure on rates and contribute to the oft-cited 'death spiral' effect."[88] Ulupono proclaims: "A Hawaii that gets a full measure of energy service value from lower volumes of energy use should not be required to pay electric bills calibrated against a less-efficient benchmark."[89]

Ulupono states that the existing decoupling framework neither hinders nor supports the impact of increased load growth expected from widespread adoption of EVs, and that as EV sales increase, the RBA reduces rates, thereby improving the utilities' competitive position then the RBA reduces rates thereby and affordability.[90] Blue Planet suggests that the Commission should look at whether decoupling creates "an unfavorable drag against the utility's motivation and efforts to promote EoT," and whether it could be appropriate to allow the utility to retain some of the increased revenues specifically from increased sales through the new EV market.[91]

HECO indicates that the RBA does not seem to impact the outcomes of cost control, grid planning effectiveness, and DER Asset Effectiveness but states that the RBA does promote the outcome of

[82] DER Intervenors Brief at 10.
[83] Blue Planet Brief at PDF p. 25.
[84] Blue Planet Brief at PDF p. 42.
[85] COH Brief at 4.
[86] DER Intervenors' Brief at 11.
[87] Ulupono Brief Table at 25.
[88] Blue Planet Brief at PDF p. 16.
[89] Ulupono Brief at 15.
[90] Ulupono Brief at 40.
[91] Blue Planet Brief at PDF p. 40.

CBRE customer engagement. COH cited a HECO statement from Docket 2008-0274 where HECO suggested that decoupling should result in decreased rates over time due to lower returns on equity and lower rate case costs. COH recommends that the RBA should be more closely tracked and reviewed to determine whether HECO's claim is valid.[92]

The DER Intervenors recommend that the Commission consider whether it would be appropriate to phase out or significantly change the RBA (along with the RAM and the MPIR) and transition toward greater reliance on targeted PIM and functionalized return adjustments.[93] The County of Hawaii also recommends that the Commission should investigate whether other mechanisms more sufficiently replicate and encourage a more competitive and open market.[94] The City and County of Honolulu recommends that the Commission should reassess whether RBA benefits, costs, and risks are being equitably distributed. In Contrast, the CA finds that RBA decoupling mechanism fulfills its primary objectives and does not believe that any revision to this mechanism is needed or appropriate at this time.[95]

Earnings Sharing Mechanism ("ESM")

The CA observes that the ESM has been invoked only on two occasions since 2013. The CA submits that the absence of earnings sharing events since the RAM Cap was installed in 2015 "is likely reflective of the more constrained rate relief allowed through the capped RAM, which reduced the potential for excessive earnings."[96] The CA believes that the ESM within the RAM has served to protect ratepayers from excessive earnings, yet has had no discernable impact on customer satisfaction and empowerment.[97] In its review of the ESM, the CA provides a discussion on the potential incentive for gaming:

> "A notable consideration with ESM in place is the potential for gaming of financial outcomes by utility management. Utility expenses and capital expenditures are discretionary in the short term, creating an opportunity to influence the ESM calculations by moving discretionary costs into any calendar year with expected sharing and out of years with zero or relatively less sharing exposure."[98]

The CA notes another potential drawback of the ESM in relation to PIMs:

> "Another downside to ESM is the potential for sharing to 'blunt' the value of other cost-control incentives or PIMs, particularly if a sharing outcome is obvious to management at

[92] COH Brief at PDF p. 30.
[93] DER Intervenors Brief at 11.
[94] COH Brief at 4.
[95] CA Brief at 24.
[96] CA Brief at 49.
[97] CA Brief at 49-50.
[98] CA Brief at 50.

> times when decisions around efficiency investments or cost-control initiatives are under consideration."[99]

The CA warns that given uncertainties about future costs, inflation, interest rates and other forecasted outcomes, there is substantial risk associated with creating new or significantly modifying revenue adjustment mechanisms with parameters that may not be accurately specified. The CA cautions that this risk is amplified if PIMs with significant reward or penalty provisions are added on top of modified revenue adjustments. [100]

HECO states that the ESM reduces its incentive to control costs and provides an example of how this could occur when there is 90% flow back to customers "at upper levels".[101] In contrast, County of Hawaii argues that the ESM does support cost control as it "incentivizes cautious investing with limited risk."[102] The City and County of Honolulu suggests that the ESM does not seem to impact the achievement of reducing carbon emissions but might "disincentivize higher risk/reward investment options."[103] The City and County of Honolulu argues that "because excess returns would be an upside surprise to grid plans, the ESM likely exerts minimal influence on effective grid planning."[104] The City and County of Honolulu also states that there is a "mild indirect incentive to procure non-utility solutions."[105]

HECO argues that the ESM also does not support the outcome of capital formation:

> "Because the ESM reduces the amount of earnings above approved ROE levels on a graduated basis, it limits the earnings potential of the Companies and therefore has a dampening effect on earnings and cash flows. In addition, the ESM is asymmetric – although it shares with customers earnings above approved ROE levels, it does not allow for additional revenues to the Companies when earnings are below approved ROE levels."[106]

HECO indicates that the ESM does not seem to impact the achievement of the following outcomes: RPS achievement, reducing carbon emissions, DER effectiveness and interconnection experience, grid planning effectiveness, and customer engagement in CBRE.

Ulupono provides several critiques of the ESM:

> "The historical and sector-wide popularity of the ESM seems out of sync with its precision and usefulness. First, it creates a strong bias toward over-earning, which adds to the problem of utility-capital bias. Second, the sharing aspect of the mechanism may

[99] CA Brief at 50.
[100] CA Brief at 50-51.
[101] HECO Brief Exhibit 2 at 5.
[102] COH Brief at PDF p. 41.
[103] C&C Honolulu Brief Appendix A at 3.
[104] C&C Honolulu Brief Appendix A at 11.
[105] C&C Honolulu Brief Appendix A at 15.
[106] HECO Brief Exhibit 5 at 5 and 6.

> encourage customers to contribute to wasteful and inefficient energy use. Third, there is little evidence that sharing percentages and thresholds have any foundation in data or analysis. . .
>
> The ESM does not, by itself, encourage improvements in affordability and may actually act to reduce utility consideration of reliance on DERs that reduce earnings by reducing sales."[107]

Blue Planet contends that the ESM "may dull the incentives" of any mechanisms that allow the utility to earn rewards for achievement of reducing carbon emissions, optimizing deployment and use of DERs, and improving interconnection experience.[108]

County of Hawaii recommends that the Commission consider differential ESMs to encourage DERs and utility scale renewables "by decreasing the sharing provision for those investments to 25 percent, while retaining it at its current level for traditional utility investments."[109]

ECAC / ECRC / PPAC

Since fuel costs are significant, potentially volatile, and largely beyond the utility's control, the CA maintains that it is "necessary in at least the near- and possible mid-term to avoid placing undue negative pressure on the financial stability of the utilities."[110] However, the CA notes that the role of fuel and energy cost recovery clauses will "increasingly diminish" as Hawaii continues to progress to a clean energy industry.[111]

HECO maintains that these mechanisms promote the outcome of capital formation since "credit rating agencies view the existing ECAC very favorably, [and] PPAC has resulted in a lowering of S&P's risk factor for Hawaiian Electric's imputed debt from 50% to 25%."[112] HECO contends that without ECAC, there would be no MYRP because companies would need frequent rate cases to recover increases or credit decreases in fuel costs due to volatile fuel prices.[113] Ulupono also discusses how the ECAC lowers utility cost of capital but the new risk sharing of 2% "has sent signal to market that could increase [cost of capital]."[114]

The City and County of Honolulu and Blue Planet argue that these mechanisms do not promote the outcome of reducing carbon emissions. Blue Planet states that these provisions "mask the costs and risks of relying on fossil fuel resources and negate the advantages of lower-cost, fixed-

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107 Ulupono Brief at 11.
108 Blue Planet Brief at PDF p. 42.
109 COH Brief at PDF p. 64
110 CA Brief at 29.
111 CA Brief at 29.
112 HECO Brief Exhibit 5 at 6.
113 HECO Brief Exhibit 2 at 6.
114 Ulupono Brief at 43.

price renewable resources in relation to the volatile costs of fossil fuels. This creates an inherent drag against moving off of fossil fuel and reducing carbon intensity."[115]

The City and County of Honolulu explains how heat rate provisions send the wrong signal and may lead to higher minimum generation and curtailment of renewables.[116] Ulupono expresses that heat rate related PIMs "suffer if the utility is required to accommodate new renewables by running its fossil plants at minimum load."[117] Blue Planet discussed how pass-through mechanisms have created a "moral hazard" for utilities, "insulating them from price risk and thereby inducing them to invest in fossil generation."[118] HECO states that widening of dead bands reduces disincentive to incorporate RE by reducing risk of low load operation, and that this would support the outcome of RPS achievement.[119]

The City and County of Honolulu states that "while PPAC takes away a negative incentive for third-party generation, PPAC also insulate[s] fossil fuel generation from independent power producers and allow[s] HECO to shift the carbon burden."[120] The CA explains that while the PPAC is "not designed for cost control," the commission's review of new purchased resources tends to mitigate this risk. Therefore, the CA attests that the PPAC is neither supportive nor detractive from the cost-control and affordability outcome.

Blue Planet believes that the PPAC incents achievement of the EoT outcomes as it "facilitates the acquisition of new renewable purchased power that will be needed to serve the growing electrified transportation market." COH believes that these mechanisms can make EoT "more feasible" as they positively affect HECO's credit worthiness.

The City and County of Honolulu maintains that the ECRC is a "step in the right direction, but still not equitable." Likewise, Ulupono argues that the current ECAC risk sharing of 2% is "insufficient to provide shareholder value signal to significantly accelerate renewables, even if they are lower cost than the fuel displaced."[121]

The CA argues that these mechanisms do not promote the outcome of customer satisfaction as they have a negative impact on rate and bill volatility. Similarly, the City and County of Honolulu contends that the ECAC "takes incentive away from utilities to manage fuel risk cost" therefore inhibiting the outcome of cost control.[122] COH finds that these mechanisms are a disincentive to achieving the outcomes of affordability and cost control.[123]

[115] Blue Planet Brief at PDF p. 8.
[116] C&C Honolulu Brief Appendix A at 3.
[117] Ulupono Brief at 35.
[118] Blue Planet Brief at PDF p. 26.
[119] HECO Brief Exhibit 1 at 7.
[120] C&C Honolulu Appendix A at 3.
[121] Ulupono Brief at 33.
[122] C&C Honolulu Appendix A at 3.
[123] COH Brief at PDF p. 42.

The CA states that the heat rate incentives and the sharing mechanism recently introduced for the ECRC may instill some cost control, but that overall, ECAC/ECRC do little to encourage cost control by the utility's management:

> "[I]n the absence of a cost recovery mechanism purposely designed to be asymmetrical, the ability to retain the benefits of price decreases within the deadband and recent sharing mechanism will not provide meaningful incentives for cost control."[124]

The CA recommends that there should be less frequent ECRC rate adjustments (perhaps quarterly instead of monthly) and cites examples of how fuel costs are reconciled, adjusted, and banked in states such as Texas, Missouri, Arizona, Kansas, and California.[125] The CA also recommends that actual fuel inventory prices should be used instead of utility projected prices to avoid the potential gaming incentive, and that this would not detrimentally impact fuel cost recovery but would only impact bills and promote affordability.[126] The CA points out that there is "an inherent gaming incentive to project changes in fuel prices, either for purposes of resetting the annual benchmark price around which partial adjustments are determined, or for calculation of monthly adjustments, in a manner that could be advantageous to the utility."[127] The CA argues that using historical, actual fuel inventory prices reduces the potential for gaming the information used to establish the annual price sharing base, thus improving cost control and accountability.[128]

The CA recommends that there should be regular fuel cost financial and prudence audits and that the ECAC / ECRC filings should undergo more intensive regulatory review.[129] The CA supports a former Commission proposal to retain an independent contractor to conduct a detailed financial and management audit of the fuel and purchased energy costs incurred and recovered by the HECO Companies through the ECAC and that it may be appropriate to open a new ECAC docket.[130] Likewise, the County of Hawaii and the DER Intervenors recommend that Commission should regularly assess the relative value and effectiveness of adjustment mechanisms.

The CA states that these mechanisms are unlikely to impact the outcomes of service quality and customer satisfaction customer empowerment, resource and system planning, or cybersecurity. HECO states that these mechanisms are unlikely to impact the outcomes of DER effectiveness, interconnection experience, grid planning effectiveness, or customer engagement in CBRE.

<u>Renewable Energy Infrastructure Program ("REIP")</u>

Only HECO and the CA provided an assessment of the REIP, and the two Parties appear to have opposing views on the efficacy of this mechanism. The CA maintains that the REIP represents

[124] CA Brief at 31.
[125] CA Brief at 33-40.
[126] CA Brief at 36-37.
[127] CA Brief at 37
[128] CA Brief at 37.
[129] CA Brief at 39.
[130] CA Brief at 35.

single-issue or "piecemeal" ratemaking and is inconsistent with the Cost Control and Affordability Outcomes because it results in higher rates often with "inadequate accounting for offsetting reductions in other expenses."[131] The CA states:

> "[T]he utilities are highly motivated to secure piecemeal rate increases between rate cases and above the RAM Cap for any new project or growing expense that can satisfy the any recovery standards."[132]

The CA argues that the REIP "may no longer be necessary, since the PPAC recovers changes in new renewable purchased power charges and the MPIR can address new major projects, including utility owned renewable generation."[133] The CA recommends the Commission to consider elimination of elimination of single-issue, piecemeal cost recovery mechanisms like the REIP as part of a broader effort to simplify and provide more incentives within a new regulatory framework.[134]

In contrast, HECO maintains that REIP incents the achievement of the following outcomes: DER Effectiveness, Grid Planning Effectiveness, Customer Engagement in CBRE, and Capital Formation.[135] HECO states that the REIP can be viewed as positive to the extent that it allows for the recovery of interconnection costs in the interim period between rate cases.[136] HECO suggests that the REIP can be viewed as an alternative recovery mechanism for initiatives like the Grid Modernization Strategy, which will be important overall for the interconnection of DER resources. HECO states that CBRE project interconnection costs or utility-owned CBRE facilities may be recoverable under REIP.[137]

<u>Reporting Metrics</u>

The CA is the only Party that discussed how existing reporting metrics act as a performance incentive. Reporting metrics are grouped into several categories, including: power supply and generation; renewable energy; customer service; financial; safety; rates and revenues; and emerging technologies. The CA suggests that while these metrics provide very useful information, they do not provide an especially strong incentive for the utilities to improve performance because there are no targets applied and no financial rewards or penalties associated with them.[138] In its assessment of the Customer Engagement outcome, the County of Hawaii poses the question: "How well trafficked is the HECO web site where the metrics are posted?"[139]

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[131] CA Brief at 47.
[132] CA Brief at 47.
[133] CA Brief at 48.
[134] CA Brief at 47.
[135] HECO Brief Exhibit 4 at 8, Exhibit 5 at 10, Exhibit 7 at 33.
[136] HECO Brief Exhibit 1 at 7
[137] HECO Exhibit 6 at 7.
[138] CA Brief at 53.
[139] COH Brief at 5.

Service Quality PIMs

Many of the Parties discuss how the reliability and customer service PIMs are merely "backstop" PIMs to prevent unacceptable performance and that they do not provide much incentive to improve performance.[140] The CA states that these PIMs are limited to a small set of customer service quality areas but do offer the advantage of providing strong financial incentives to provide a minimum level of reliability and call center service.[141]

The City and County of Honolulu states that SAIDI and SAIFI do not support the Cost Control outcome because they "control for long-term outages and thus provide suboptimal signals for utility performance and cost control related to grid resilience."[142]

The City and County of Honolulu claims that SAIDI represents a "narrow view" of reliability and new measures must be considered when planning for resiliency "(e.g., recovery time and previsioning of critical services)."[143] The City and County of Honolulu suggests that the following outcomes should be promoted through Service Quality PIMS: 1) effective community engagement and integration of community input in terms of grid planning, 2) responsiveness to customers seeking info on interconnection should be promoted, 3) reporting and performance standards for DER procurement.[144]

Blue Planet also suggests that there should be a targeted PIM that can more specifically address the outcomes of Interconnection Experience and Stakeholder Engagement.[145]

HECO states that the current Service Quality PIMs may not necessarily incent RPS Achievement as the "risk of penalty for not meeting reliability targets poses some disincentive for rapid integration."[146] HECO maintains that SAIDI and SAIFI promote Grid Planning Effectiveness as they "help to promote attention to reliability in the IGP process."[147]

HECO states that call centers "are critical to addressing customer interconnection status and inquiries" and therefore incent achievement of the Interconnection Experience outcome.[148] HECO argues that the current Service Quality PIMs do not support the achievement of the Cost Control outcome since they "act as a counterbalance to cost control" [149] as utilities must expend dollars to avoid penalties. However, HECO does believe that the Targeted Energy Policy PIMs promote Cost Control.[150]

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[140] See for Example CA Brief at 54, C&C of Honolulu Brief Appendix A at 11, Blue Planet Brief Attachment 5 at 5.
[141] CA Brief at 55.
[142] C&C of Honolulu Brief Appendix A at 7.
[143] C&C of Honolulu Brief Appendix A at 11.
[144] C&C of Honolulu Brief Appendix A at 11 & 15.
[145] Blue Planet Brief Attachment 5 at 5.
[146] HECO Brief Exhibit 1 at 5.
[147] HECO Brief Exhibit 3 at 4.
[148] HECO Brief Exhibit 4 at 5-6.
[149] HECO Brief Exhibit 2 at 7.
[150] Id.

Targeted Energy Policy PIMs

Many Parties believe that the Demand Response ("DR") and Renewable Generation PIMs provide a meaningful incentive to help promote specific resources. Parties appreciate that these PIMS are tied to sustainability and resilience goals. HECO maintains that these PIMS "mitigate capital bias perception."[151]

The CA warns that the DR PIM presents a perverse gaming incentive:

> "The demand response incentive provides an incentive to implement demand response contracts, but since the amount of the incentive is based on the contract value it might create the perverse incentive of unduly increasing demand response contract costs."[152]

The CA also argues that cost control incentives are needed for the DR PIM:

> "[The DR PIM] also does not provide any incentive to control costs, to find more cost-effective solutions, to expand customer participation, or to ensure that all customers receive benefits."[153]

The City and County of Honolulu argues that more transparency is needed to allow for more prudent management of the Targeted Energy Policy PIMs. Blue Planet explains how it is "generally unclear whether the scale of the penalties and rewards connected to the current PIMs are meaningful"[154] and COH states that "real quantitative data regarding these PIMs' impact on affordability is limited."[155]

The CA suggests that the Commission should consider establishing new PIMs to incentivize better resource and system planning, "because of the importance of this area and the utilities' poor performance in this area in recent years."[156]

The CA offers a general PIM design recommendation:

> "Any PIM applied to the utilities must (a) not create perverse incentives, and (b) not encourage a utility to incur costs that exceed the benefits of the PIM."[157]

COH suggests that targeted PIMs have the potential to be deployed for EoT, "in particular for those areas of EoT expansion that will not immediately benefit the utility."[158]

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[151] HECO Brief Exhibit 1 at 5.
[152] CA Brief at 55.
[153] CA Brief at 55.
[154] Blue Planet Brief at PDF p. 8.
[155] COH Brief at PDF p. 32.
[156] CA Brief at 56.
[157] CA at 56
[158] COH Brief Appendix 1 Electrification of Transportation at 6.

Renewable Portfolio Standards ("RPS")

Most of the Parties find that the RPS incents the achievement of many of the identified outcomes including Reducing GHG Emissions, Cost Control, Grid Planning Effectiveness, Grid Solutions Procurement Transparency, Corporate Sustainability and Resilience, Affordability, EoT, and Resilience.

The CA states:

> "The RPS, if implemented efficiently and subject to effective long-term planning, can help support the cost control and affordability outcome, particularly over the long-run by allowing for lower, more stable electricity costs and helping to comply with Hawaii's climate and environmental requirements. The RPS has the disadvantage of increasing electricity costs in the short-term."[159]

The City and County believes that the RPS formula should be updated to address "total system carbon reductions."[160]

Ulupono points out that the RPS formula allows the utility to claim higher RPS achievement than actual renewable generation/total generation and that the utility may lack incentive to correct this formula.[161]

HECO provides some critique about the RPS being a "Penalty-only incentive":[162]

> "The existing RPS mechanism provides an incentive to achieve RPS targets through the risk of penalties for non-compliance. However, providing a penalty-only incentive to achieve the State's aggressive 100% RPS goal arguably discounts the magnitude of the innovation, effort and risk required to be successful. Penalty-only incentives usually are applied to conventional or normal expectations. Symmetrical incentives could provide positive additional encouragement and support for achieving or even exceeding such critical and historic state energy goals, as long as this is balanced by considerations of cost-effectiveness."[163]

Energy Efficiency Portfolio Standard ("EEPS")

Similar to the RPS, most of the Parties find that EEPS incents the achievement of many of the identified outcomes including Reducing GHG Emissions, Cost Control, Grid Planning Effectiveness, Grid Solutions Procurement Transparency, Corporate Sustainability and Resilience, Affordability, EoT, Unbiased Capex/Opex Decisions, and Resilience.

[159] CA Brief at 57
[160] C&C Appendix A at 6.
[161] Ulupono Brief at 34
[162] HECO Brief Exhibit 1 at 6.
[163] HECO Brief Exhibit 5 at 8.

Blue Planet explains how EEPS and EoT may be in “general tension with each other since EoT will require substantial increases in load.”[164] Blue Planet acknowledges that consumers may see EVs as more efficient than internal combustion engine vehicles. Blue Planet makes the following recommendation:

> “The Commission should remain aware of the tension between EE and EoT and ensure that these outcomes do not undermine each other. Either the outcomes and their metrics must be kept separate and distinct, or they may need to be combined in a more holistic outcome and metric of "system- wide" energy efficiency, including transportation.”[165]

COH similarly suggests that “as EoT progresses, the HECO and the EEPS third party administrator should analyze whether there are opportunities for co-marketing of electric vehicle-related services and energy efficiency measures.”[166] COH also suggests that EEPS should better target low-income households and renters.

HECO maintains that EEPs could disincentivize the achievement of the Grid Planning Effectiveness outcome because “[t]he structure of having a separate entity develop one of the inputs to the planning process on a stand-alone basis can lead to inefficiencies and lost opportunities.”[167]

The CA suggests that the resource and system planning process should “more effectively evaluate and integrate cost-effective energy efficiency resources into the utility resource plans, including those energy efficiency resources implemented by Hawaii Energy, by customers, and by third parties.”[168]

HECO believes that CBRE has a positive impact on EEPS:

> “[CBRE] likely has a positive impact on EEPS in terms of de-linking renewable generation supply from the customer’s demand, which will allow CBRE and EEPS to be complementary. In other words, CBRE is less likely to encourage a participating customer from adding load to utilize any excess generation.”[169]

[164] Blue Planet Brief Attachment 4 at 6.
[165] Id.
[166] COH Brief Appendix 1 Electrification of Transportation at 8.
[167] HECO Brief Exhibit 7 at 31.
[168] CA Brief at 60
[169] HECO Brief Exhibit 6 at 6.