BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAI'I

In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC. HAWAI'I ELECTRIC LIGHT COMPANY, INC. MAUI ELECTRIC COMPANY, LIMITED For approval to commit funds in excess of $2,500,000 for the Phase 1 Grid Modernization Project, to Defer Certain Computer Software Development Costs, to Recover the Capital and Deferred Costs through the Major Project Interim Recovery, and Related Requests.	DOCKET NO. 2018-0141

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APPLICATION OF
HAWAIIAN ELECTRIC COMPANY, INC.,
HAWAI'I ELECTRIC LIGHT COMPANY, INC. AND
MAUI ELECTRIC COMPANY, LIMITED

VERIFICATION

EXHIBITS "A"-"L"

AND

CERTIFICATE OF SERVICE

Joseph P. Viola
Vice President, Regulatory Affairs
Hawaiian Electric Company, Inc.

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Maui Electric Company, Limited

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APPLICATION

TO THE HONORABLE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAIʻI:

By this Application, Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Hawaiʻi Electric Light Company, Inc. ("Hawaiʻi Electric Light") and Maui Electric Company, Limited ("Maui Electric") respectfully request approvals necessary to implement the first phase ("Phase 1") of their Grid Modernization Strategy ("GMS") implementation.[1]

[1] Hawaiian Electric, Hawaiʻi Electric Light and Maui Electric and are collectively referred to as the "Hawaiian Electric Companies" or "Companies."

I. EXECUTIVE SUMMARY

Meeting customers' needs and achieving the State's renewable portfolio standards goals are not possible with the Hawaiian Electric Companies' current electric grid; *the grid we have is not the grid we need*.

For Hawai'i, an advanced, resilient and modernized grid is foundational to serving customers with affordable and reliable electric service, while also transforming the system to achieve a renewable energy future. Hawai'i has the highest penetration of customer-owned photovoltaic systems in the country. As set forth in the GMS, a modernized grid will enable incorporation of more renewable energy resources and intergration of new technologies. It will enable customer energy options, including Demand Response ("DR") and Distributed Energy Resources ("DER") programs, Time-of-Use ("TOU") rates, and capabilities to provide customers insight to better manage their energy usage. GMS will provide the modernized platform for evolving needs and expectations of Hawai'i's communities and stakeholders. Ultimately, the Companies' GMS implementation will advance state energy policies and provide customers and communities with improved service, tools, offerings and capabilities.

Creating a modern electric grid is not a one-step process. A sequential series of GMS implementations are necessary to build a grid that is capable of evolving into a conduit for coordinated import and export of energy and related services, combining both distributed resources from customer energy options, as well as grid-scale resources, to balance electricity supply and demand. Building on input from the Commission and other stakeholders, the Companies have developed a strategy to implement GMS proportionally over multiple phases. This phased approach will align customer value and affordability with identified incremental grid investments.

The Companies are proposing to deploy Phase 1 in a targeted, as-needed, where-needed manner that will maximize value for customers while mitigating risk and minimizing rate impacts. Specifically, Phase 1 consists of investments in the following three technologies, which already are functionally mature and have been deployed elsewhere in the industry:

1. Advanced meters with integrated communications, which record electricity demand, usage and power characteristics in configurable intervals, as well as send notifications for anomalous conditions to provide the Companies with more insight into the distribution grid and support the Companies' growing portfolio of customer energy options;

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

3. An interoperable, scalable telecommunications network, which enables the communication path for both advanced meters and field devices for distribution sensing, control and automation.

These three foundational platform components support each other, with a focus on the near-term approach laid out in the GMS to ensure flexibility over the longer term and to adjust to changing circumstances, including considerations from the Companies' Integrated Grid Planning process and technological innovations. Together, they will create value through cross-programmatic functionalities and technologies. Phase 1 will also provide the basis for future GMS deployments, such as an Advanced Distribution Management System and other field devices necessary to increase grid efficiency and resilience while continuing to grow customer options and utility-based program opportunities in Hawai‘i, such as electrification of transportation and electric vehicle expansion.

Additional elements of the Phase 1 deployment include:

- Improved metering functionality and efficiency to support the Companies' current Smart Export, Controlled Customer Grid Supply Plus and Demand Response programs, as well as future customer energy options; and
- Advanced metering sensing and control capability that will provide valuable operational data and control.

Phase 1 is expected to be cost-beneficial under a lowest reasonable cost analysis, and when considered in the context of enabling distributed customer energy options that can provide more cost-effective alternatives to traditional wired investments. Phase 1 is also justified under a "holistic" approach employed in other jusrisdictions for evaluating the benefits of grid modernization investments, which the Companies maintain is an appropriate approach here as well.

The Companies are proposing to implement Phase 1 over the 2019-2023 timeframe at a total estimated cost of approximately $86.3 million, and to recover the costs of Phase 1 through the Major Project Interim Recovery adjustment mechanism until base rates that reflect the revenue requirements associated with the costs of Phase 1 take effect in a future rate case for each respective company.

II. REQUESTED APPROVALS

The Hawaiian Electric Companies respectfully request a decision and order approving:

(1) Implementation of the proposed Phase 1 of the GMS (at a total current estimated cost of $86.3 million), as further described in Exhibit H;

(2) A commitment of funds in excess of $2.5 million for the capital costs of Phase 1, as further described in Exhibits B and H ("Capital Costs") pursuant to Paragraph 2.3(g)(2) of the Commission's General Order No. 7, as modified by Decision and Order No. ("D&O") 21002, filed May 27, 2004 in Docket No. 03-0257 ("G.O. 7");

(3) The proposed accounting and ratemaking treatment for Phase 1, as further described in Exhibit C, including:

(a) Deferral of the software costs of Phase 1, as further described in Exhibits B and H pursuant to the Companies' policy for *Accounting for the Costs of Computer Software Developed or Obtained for Internal Use* ("Software Accounting Policy") and D&O 18365, filed February 8, 2001 in Docket No. 99-0207 ("D&O 18365");

(b) Accrual of an allowance for funds used during construction ("AFUDC"), as appropriate, during the applicable construction periods of Phase 1, as further described in Exhibit C;

(c) As further described in Exhibits D and J, recovery of the Capital Costs and Deferred Costs ("Deferred Costs") through the Major Project Interim Recovery ("MPIR") adjustment mechanism ("Mechanism") established in

Order No. 34514, filed April 27, 2017 in Docket No. 2013-0141,[2] until base rates that reflect the revenue requirements associated with the Capital Costs and Deferred Costs of Phase 1 take effect in a future rate case for each respective company, provided however that if the Commission is not inclined to allow the Companies to recover the Deferred Costs through the MPIR Mechanism, then in the alternative, the Companies request approval to recover the Deferred Costs through:

(i) the Renewable Energy Infrastructure Program Surcharge ("REIP Surcharge") approved in the *D&O* filed on December 30, 2009 in Docket No. 2007-0416 ("REIP D&O"), until base rates that reflect the revenue requirements associated with the Deferred Costs take effect in a future rate case for each respective company; provided further that if the Commission is not inclined to allow recovery of the Deferred Costs through either the MPIR Mechanism or REIP Surcharge, then the Companies propose to recover the Deferred Costs through;

(ii) a future rate case for each respective company, with amortization of the Deferred Costs commencing when base rates that reflect the Deferred Costs take effect in those respective proceedings; and

(4) Such other and further relief as may be just and equitable in the premises.

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[2] The Commission's *MPIR Guidelines* ("MPIR Guidelines") are set forth in Attachment A to Order No. 34514 *Establishing Performance Incentive Measures and Addressing Outstanding Schedule B Issues* ("Order 34514"), filed April 27, 2017 in Docket No. 2013-0141 (Decoupling Reexamination).

III. APPLICANTS

Hawaiian Electric, whose principal place of business and whose executive offices are located at 900 Richards Street, Honolulu, Hawai‘i, is a corporation duly organized under the laws of the Kingdom of Hawai‘i on or about October 13, 1891, and now exists under and by virtue of the laws of the State of Hawai‘i. Hawaiian Electric is an operating public utility engaged in the production, purchase, transmission, distribution, and sale of electricity on the island of O‘ahu.

Hawai‘i Electric Light, whose principal place of business and whose executive offices are located at 1200 Kilauea Avenue, Hilo, Hawai‘i, is a corporation duly organized under the laws of the Republic of Hawai‘i on or about December 5, 1894, and now exists under and by virtue of the laws of the State of Hawai‘i. Hawai‘i Electric Light is an operating public utility engaged in the production, purchase, transmission, distribution, and sale of electricity on the island of Hawai‘i.

Maui Electric, whose principal place of business and whose executive offices are located at 210 Kamehameha Avenue, Kahului, Maui, Hawai‘i, is a corporation duly organized under the laws of the Territory of Hawai‘i on or about April 28, 1921, and now exists under and by virtue of the laws of the State of Hawai‘i. Maui Electric is an operating public utility engaged in the production, purchase, transmission, distribution, and sale of electricity on the island of Maui; the production, transmission, distribution, and sale of electricity on the island of Moloka‘i; and the production, purchase, distribution, and sale of electricity on the island of Lana‘i.

IV. CORRESPONDENCE

Correspondence and communications with regard to this Application should be addressed to:

Kevin M. Katsura
Manager, Regulatory Non-Rate Proceedings
Hawaiian Electric Company, Inc.
P. O. Box 2750
Honolulu, Hawai‘i 96840-0001

V. STATUTORY PROVISION OR AUTHORITY

The approvals in this Application are requested pursuant to Sections 269-6, 269-7, 269-16, 269-94, and 269-95(1) of the Hawai‘i Revised Statutes (“HRS”), Sections 6-61-74 and 6-61-86 of the *Rules of Practice an Procedure Before the Public Utilities Commission*, Title 6, Chapter 61 of the Hawai‘i Administrative Rules, G.O. 7 Paragraph 2.3(g)(2), D&O 18365, the REIP D&O, Order 34514, and D&O 35268 (“D&O 35368”), filed February 7, 2018 in Docket No. 2017-0226 (the “GMS Docket”).

VI. EXHIBITS

The following exhibits are provided in support of this Application:

Exhibit A	–	Grid Modernization Strategy Working Plan
Exhibit B	–	Project Justification with Business Case Support
Exhibit C	–	Accounting and Ratemaking Treatment
Exhibit D	–	Interim Recovery
Exhibit E	–	Request for Proposals
Exhibit F	–	Stakeholder Engagement and Customer Safeguards
Exhibit G	–	Telecommunications Network Considerations
Exhibit H	–	GMS Phase 1 Project Costs

Exhibit I – Bill Impact

Exhibit J – Hawaiian Electric Companies' Decoupling Calculation Workbook

Exhibit K – Glossary of Terms

Exhibit L – Confidentiality Justification

VII. GRID MODERNIZATION STRATEGY

The GMS provides near- and long-term plans for the Companies to deploy advanced technologies and back office systems that will integrate new technologies and processes with the existing infrastructure to update the electric grid, which will pave the way for the Companies to achieve Hawaiʻi's 100% Renewable Portfolio Standards ("RPS") goal by 2045.[3]

A. GMS BACKGROUND

The *Commission's Inclinations on the Future of Hawaiʻi's Electric Utilities* ("Inclinations")[4] provided guidance for the development and implementation of a modernized grid, including a focus on delivering immediate value to customers with smart grid infrastructure, enabling customer-sited distributed energy resources ("DER"), working with third-party service providers to maximize customer benefits, and developing and maintaining updated data privacy policies.[5]

Subsequent guidance from the Commission explained that:

> [A] modernized grid is the "backbone" necessary to advance the State's RPS goals, support integration of additional levels of renewables, encourage competition, empower consumers to make their own choices

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[3] See Hawaiʻi State Energy Office, Grid Modernization, Renewable Portfolio Standard targets, available at http://energy.hawaii.gov/renewable-energy/grid-modernization.
[4] See Docket No. 2012-0036, D&O 32052, *Exhibit A*, issued April 28, 2014.
[5] See id. at 14-15.

> concerning the level and types of electric service they desire, and leverage customer-sited resources to assist in grid operation.[6]

In accordance with the Commission's guidance for developing a GMS, the Companies filed their draft GMS, *Modernizing Hawai'i's Grid For Our Customers*, on June 30, 2017 under Docket No. 2016-0087. After obtaining several months' worth of comments and feedback on the draft GMS from stakeholder, public and focus group meetings, as well as online input, the Companies' final GMS report was filed on August 29, 2017 in the GMS Docket, which served as a repository for public comments on the Companies' final GMS that were received in September 2017.

On February 7, 2018, the Commission issued D&O 35268 in the GMS Docket, finding that the GMS reasonably complies with the Commission's earlier directives, providing additional directives, and ordering the Companies to implement their GMS in accordance with the Commission's directives.[7]

B. GUIDING PRINCIPLES

In accordance with the Commission's directives in D&O 35268, and in response to conversations held since the Companies filed their final GMS, the Companies are now moving forward with their submission of supporting applications that align with the program descriptions and expectations provided in the GMS. The Companies are dedicated to ensuring that their GMS-related project applications align with Commission- and Legislature-developed guiding principles.[8]

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[6] See Docket No. 2016-0087, Order No. 34281, filed January 4, 2017 ("Order 34281"), at 2.
[7] See D&O 35268 at 39-40.
[8] See, e.g., HRS § 269-145.5(b).

It is essential that all customers appropriately benefit from any costs incurred to advance the State's policies and related grid modernization investments. As such, the Companies proposed adapting and expanding the Commission's interpretation of Hawai'i's legislative guiding principles to ensure alignment with customer and stakeholder interests, as well as with GMS implementation. These guiding principles are necessary to counsel and provide a framework for grid modernization decisions by the Companies while moving forward with customers and stakeholders to achieve Hawai'i's RPS goals. As summarized in the GMS, the Hawaiian Electric Companies' guiding principles[9] to inform grid modernization are as follows:

- Enable greater customer engagement, empowerment, and options for utilizing and providing energy services;
- Maintain and enhance the safety, security, reliability, and resiliency of the electric grid, at fair and reasonable costs, consistent with the State's energy policy goals;
- Facilitate comprehensive, coordinated, transparent, and integrated grid planning across distribution, transmission, and resource planning;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
- Ensure optimized utilization of resources and electricity grid assets to minimize total system costs for the benefit of all customers; and
- Determine fair cost allocation and fair compensation for electric grid services and benefits provided to and by customers and other non-utility service providers.

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[9] See GMS, Section 1 (Vision, Definition & Scope), at 2.

C. GMS PHASE 1 PLATFORM

This Application serves as the initial groundwork to build the platform that is needed to create the foundation for a modernized grid that is consistent with the Commission's principles.[10] Accordingly, the goal of Phase 1 is to deploy three fundamental platform investments:

1. Advanced meters with integrated communications, which record electricity demand, usage, and power characteristics in configurable intervals as well as send notifications for anomalous conditions to provide the Companies with more insight into the distribution grid and support the Companies' growing portfolio of customer energy options;[11]

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

3. An interoperable, scalable telecommunications network, which enables the communication path for both advanced meters and field devices for distribution sensing, control, and automation.

These three foundational platform components support each other, and their synergies bring additional value through cross-programmatic functionalities and technologies.

The Companies realize that meeting customers' needs and achieving the State's RPS goals are not possible with the current grid; *the grid we have is not the grid we need*. This Application is the first in a series for grid modernization that recognize that the existing electric grid is unable to either fulfill the needs and requirements to support policies being pursued in the State of Hawai'i, or to otherwise satisfy the expectations of customers. The Companies further

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[10] Id. Section D, (Guiding Principles), at 51-52.
[11] The term "customer energy options" as utilized in this Application is inclusive of existing and new tariffs and/or programs including Demand Response ("DR") Portfolios (including Time-of-Use ("TOU") and future dynamic pricing) and DER programs. All of these options would be inclusive of any customer-sited resources, including but not limited to photovoltaics ("PV"), distributed storage, and electric vehicles ("EVs").

recognize that creating a modern, sustainable and resilient grid is not a one-step exercise, and therefore a sequential series of GMS implementations are necessary to expand upon the features included as part of Phase 1 by adding additional systems and technologies to enable grid sensing, control, and automation with a logical progression of technology solutions.

D. RELATED PROGRAMS AND INITIATIVES

The Companies have also proposed an ongoing Integrated Grid Planning ("IGP") approach to harmonize the resource, transmission, and distribution planning processes by integrating information and alternatives from all sources and levels.[12] Consistent with this methodology and the Commission's acceptance of the Companies' *PSIP Update Report: December 2016*,[13] the Companies' IGP filing provides a more detailed planning framework, the output of which will help identify future priorities for grid investment and modernization.

The Companies understand the need to harmonize their near- and long-term plans, as well as provide a clear pathway for how each will work together to address the Commission's *Inclinations* and achieve the State's RPS goals. Figure 1 below provides a visual representation of the interrelationships between the Companies' GMS and how it will feed into their PSIP, DER, IGP and DR-related programs. Beginning with Phase 1, the platform developed and deployed as part of the GMS will drive the grid toward achieving more renewable penetration (as described in the PSIP), enable more customer energy options, and enable exploration of alternatives to meet the needs and expectations of Hawai‘i's communities and stakeholders to modernize the electric grid, as proposed in the IGP filing. Collectively, these plans and programs lay out a conceptual framework for the Companies to successfully innovate and

[12] See Hawaiian Electric Companies' *Planning Hawai‘i's Grid for Future Generations – Integrated Grid Planning Report*, filed March 1, 2018, available at www.hawaiianelectric.com/igp.
[13] See Docket No. 2014-0183 ("PSIP"), D&O 34696, issued July 14, 2017.

achieve necessary enhancements while continuing to pursue advanced technologies that appeal to customers' needs and interests.

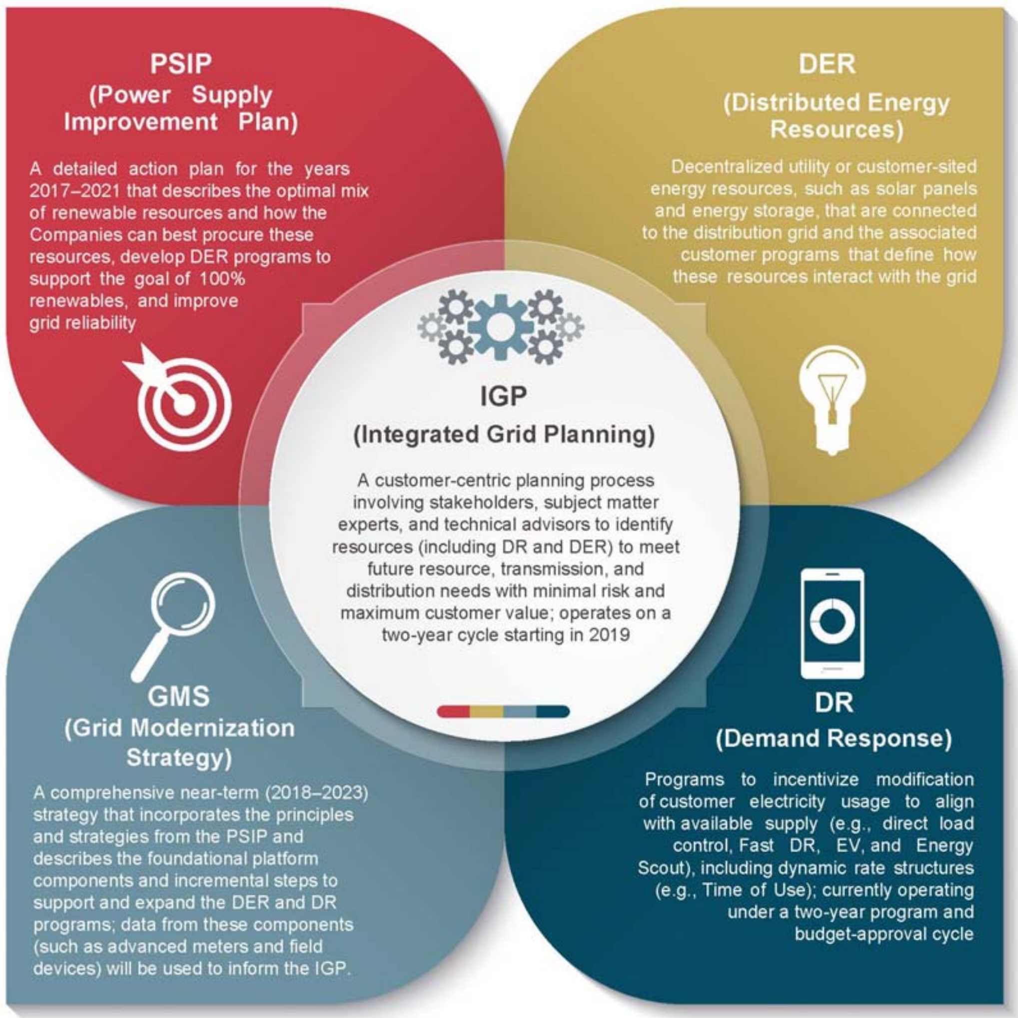

Figure 1

Modernizing Hawai'i's electric grid is foundational to serving customers with affordable, reliable and resilient electric service while also transforming the system to achieve a renewable energy future that is sustainable and enables customer energy options. Programs and policies are being pursued to progress toward the State's RPS goals, which include requiring 100% of net

electricity sales to be provided from renewable energy by the end of 2045.[14] With the highest penetration of customer-owned PV systems in the country,[15] the Companies' GMS implementation will build the platform to provide customers with improved service, tools and offerings, while simultaneously achieving policy milestones.

Several dockets before the Commission are exploring different initiatives to enable DER as a component of Hawai'i's RPS portfolio while continuing to serve customers with safe and reliable electricity. Grid modernization investments, beginning with this Phase 1, will enable functionality needed by the programs, rates and tariffs being reviewed in a variety of proceedings, such as:

- Docket No. 2014-0183 – PSIP;
- Docket No. 2014-0192 – DER Policies, including exploration of TOU tariffs[16] and establishment of Smart Export and Controlled Customer Grid Supply Plus ("CGS+") programs;[17]
- Docket No. 2015-0389 – Community-Based Renewable Energy Program;
- Docket Nos. 2015-0411 and 2015-0412 – DR Management System ("DRMS") and DR Portfolio, respectively;[18]
- Docket No. 2016-0168 – Electrification of Transportation ("EoT") Strategic Roadmap.

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[14] See Hawai'i State Energy Office *Grid Modernization, RPS targets*, available at http://energy.hawaii.gov/renewable-energy/grid-modernization.
[15] In 2017, approximately 27 percent of the Companies' customers' energy needs were met with renewable generation. More than 17 percent of total customers had PV installations by the end of 2017, with additional requests pending approval into the start of 2018.
[16] See Docket No. 2014-0192, Order No. 33923, issued September 16, 2016.
[17] See D&O 34924, issued October 20, 2017.
[18] As indicated in Docket No. 2015-0411, the Companies are planning for the DRMS to evolve to a full Distributed Energy Resource Management System ("DERMS") to facilitate the utilization of the Companies' DR Portfolio and aggregated DER from others to manage the power system. Applicable capabilities will be utilized upon completion of implementation and evaluated in Phase 2 of the GMS implementation.

The advanced meters, MDMS and telecommunications network backbone are being procured in this initial phase of GMS implementation for a number of reasons:

- An advanced metering infrastructure is needed to support the recently approved CGS+, Smart Export, the DR Portfolio while enabling future customer energy options;
- The vendor community for these technologies is mature; and
- These investments represent a proportional, flexible, and scalable first step for grid modernization. Because the technology supporting grid modernization will continue to evolve, the Companies' proportional approach for deployment seeks to strike a balance between economies of scale from a full deployment and the risk of stranded assets due to obsolescence and/or inability to adopt future technological advancements.

The Companies' strategy to employ proportional implementation over multiple phases results in costs and rate impacts that are incurred over time in proportion to achieving grid capabilities and value for all customers. Some cost savings may be foregone in the near term compared to an immediate system-wide implementation, due to economies of scale; however, the cost of future implementations may be offset by lower costs or improved functionality as products further evolve, mature, and become more widespread.

Through Commission and stakeholder input, the Companies identified this proportional approach, which addresses Commission concerns,[19] to support participation in customer energy options, while simultaneously aligning customer value and affordability with identified incremental grid investments. Moreover, the sequence of technology investment, starting with Phase 1, leverages functionally mature technologies that are already deployed elsewhere in the

[19] See Docket No. 2016-0087, Order No. 34281, at 40 ("[M]etering replacement could be driven more by demand to participate in certain customer programs rather than by a mandatory roll out to all customers on an opt-out basis.").

industry. Based on survey results and approved plans, smart meter deployments in the United States are expected to reach 76 million by the end of 2017 (covering 60% of U.S. households).[20]

The initial combination of advanced meters, an MDMS, and an enhanced telecommunications network provide the necessary foundational platform required to begin the progression toward a modern grid needed to support customers' needs and the State's RPS goals. However, the full capabilities of the advanced meters, MDMS and telecommunications network cannot be realized without other foundational platform system components identified in the GMS. The interrelation and support of these investments is further discussed in Exhibits A and B, and is also briefly discussed below as a means to provide context on each of the technologies proposed.

E. FUTURE PHASES, PROGRAMS AND INITIATIVES

In addition to facilitating interval usage data, more complex tariffs and customer energy options, an important capability of advanced meters is the ability to provide outage notifications and alerts for power quality issues, such as voltage violations. As a result, these investments will increase customer satisfaction through early identification and will proactively address issues. The MDMS will make this type of data available through a report or query for planning purposes. However, in order for this information to be actionable by the Companies' operations, additional systems are needed in the second phase ("Phase 2") of the GMS implementation to receive and process the notifications and alerts.

In Phase 2, an advanced distribution automation system ("ADMS") is planned to enable distribution system monitoring, control and automation. In the case of voltage alerts from

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[20] See Institute for Electric Innovation Report, *Electric Company Smart Meter Deployments: Foundation for Smart Grid* (December 2017), available at http://www.edisonfoundation.net/iei/publications/Documents/IEI_Smart%20Meter%20Report%202017_FINAL.pdf

advanced meters, line sensors or other distribution system sensing devices, an ADMS assists operators in understanding the context of an alert and identifying potential corrective actions needed. An additional component of the ADMS is an outage management system ("OMS") that coordinates fault location, isolation and system restoration. An OMS can leverage outage alerts and other data from deployed advanced meters or other field devices to quickly identify outage restoration actions. Future phases, as illustrated in Figure 2 below, will enable further development and maturity of grid modernization capabilities.[21]

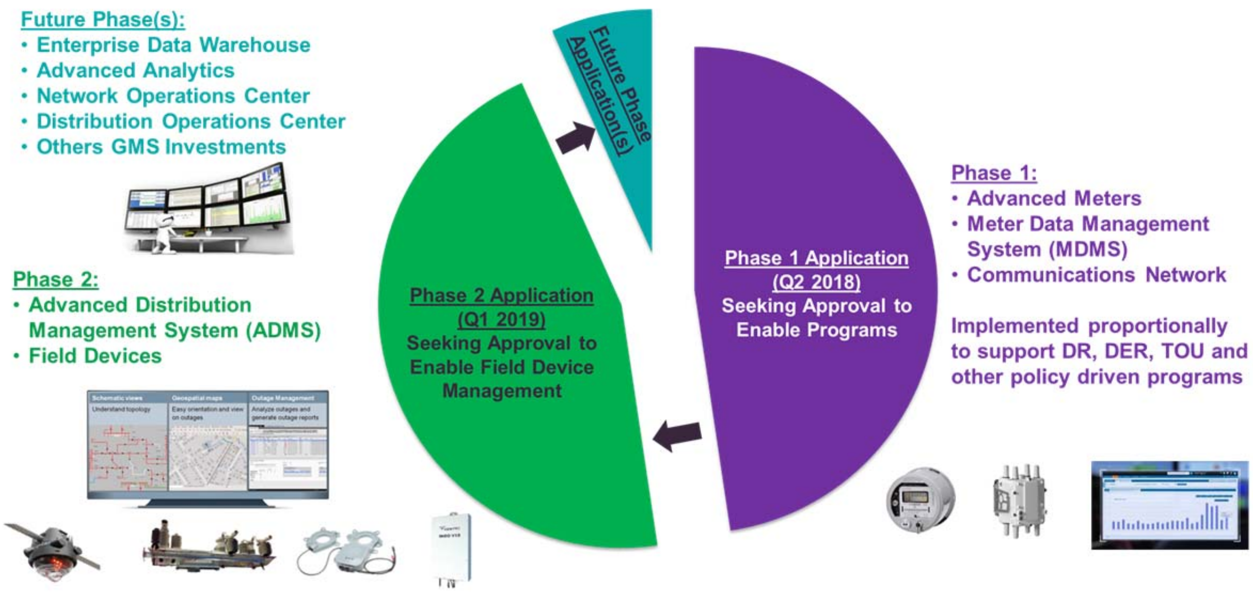

Figure 2

Beyond Phase 2, there are components that still require additional evaluation to determine the necessary scope to fulfill customer needs and stakeholder expectations. Analytics tools designed to assist in digesting all of the data collected from devices and equipment may help to fill any gaps between analytic needs and the inherent capabilities provided by the MDMS and ADMS products selected in Phases 1 and 2, respectively. In addition, a network operations

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[21] See Exhibit A, attached hereto, for further discussion of the Companies' implementation roadmap.

center ("NOC") may be needed to monitor and administer the telecommunications system, and the Companies are exploring the capabilities of the existing/planned infrastructure to support these needs. Similarly, a distribution operations center may be needed for system operators to interface with the ADMS and manage the distribution system.

The GMS proposes an investment through 2023; however, beyond 2023, the Companies will need to continue to invest in and modernize the grid. At this time the scope and scale of this future effort are not known. Technology is evolving at a rapid pace. As a result, the Companies will need to assess the needs of the customers and the grid in order to pair the appropriate technology that is available. IGP will identify any new projects and the priorities for future grid investment and modernization. Taking these into consideration, the Companies will need to evaluate at a later date whether the continued GMS efforts can proceed under the Companies' normal operating budgets (e.g., base rates and future rate cases), or whether any additional application(s) to the Commission will be required.

VIII. STAKEHOLDER ENGAGEMENT AND CUSTOMER SAFEGUARDS

Customer and stakeholder interests were at the core of the development of the Companies' GMS filings (see Exhibit F). In D&O 35268, the Commission acknowledged the Companies' efforts to improve the GMS in response to stakeholder comments and stated an expectation that the Companies "continue this best practice as they develop their application(s) to implement the Strategy."[22] Various stakeholder engagement sessions were held during the development of this Application, and feedback obtained during these meetings were integral concepts included as part of the Phase 1 implementation strategy.

[22] See D&O 35268 at 23.

The Companies also recognize that some customers have stated concerns regarding radio frequency ("RF") emissions from advanced meters, and note that scientific consensus continues to be that RF exposure does not pose any significant negative health impacts. However, in an effort to provide alternative options to customers who are not comfortable with the communications capabilities enabled by advanced meters, the Companies are also investigating power line carrier ("PLC") options as a means to transmit customer energy usage data via power lines or other viable options. The Companies plan to utilize the best methodology that addresses safety concerns and is the most cost-effective option for all customers and the Companies' grid modernization platform.

Access to data is a key part of enabling customer choice and control. As part of this application, the Companies propose a customer energy portal integrated with the MDMS with Green Button[23] functionality for customers and customer-authorized third parties to access advanced meter data. However, while these new technologies provide customers with valuable new capabilities like the customer energy portal, any new technology has the potential to expose customers to risks related to privacy and confidentiality of their data. While the Companies plan to explore system-level data sharing through the IGP process, policies are also needed regarding third-party access to customer-specific advanced metering data. The Companies intend to address the functional and technical requirements that will enable data sharing through the procurement and implementation of equipment and systems through grid modernization. However, questions regarding third-party access to customers' data, including their personally

[23] See U.S. Department of Energy, *Green Button*, available at https://www.energy.gov/data/green-button and http://www.greenbuttondata.org/.

identifiable information, need to be handled fairly and in a responsible manner. The Companies have started to research this topic to address it with the Commission separately.

The Companies have also made sure to specifically include requirements for the security of the customer energy usage information that will be collected through the advanced meters and MDMS. The requirements necessary to comply with the Companies' comprehensive cybersecurity measures were included as part of the various requests for proposals ("RFPs") issued for the MDMS and telecommunications network systems (see Exhibit E). The proposed MDMS and telecommunications network will continue to prioritize customer data security along with flexibility to evolve as the Companies' GMS continues to be implemented (see Exhibit F – Attachment 1).

The Companies will work to ensure that stakeholder interests and community concerns continue to play a key role in their grid modernization plans. Much like the stakeholder engagement sessions held during the development of the GMS and, subsequently, this Application, the Companies will continue to seek input and feedback on their GMS and other grid modernization plans as they progress through the different phases of deployment and implementation.

IX. GMS PHASE 1 PROJECT

Phase 1 of the GMS implementation focuses on the near-term approach laid out in the GMS to ensure flexibility over the longer term and adjust to changing circumstances, including considerations from the IGP process and technological innovations. To maximize benefits to customers, these near-term investments must set the foundation to allow the grid to evolve and to support continued participation in customer energy options. Effective utilization of customer

energy options as grid resources necessitates advanced grid technologies to measure, manage, integrate and leverage the potential benefits of the associated grid services.

A. PROJECT DESCRIPTION

Within the scope of the GMS, the electric grid will be capable of evolving into a conduit for coordinated import and export of energy and related services, combining both distributed resources from customer energy options, as well as grid-scale resources to balance electricity supply and demand. This evolution begins with the three components of GMS Phase 1: (1) advanced meters, (2) the MDMS, and (3) the telecommunications network.

1. ADVANCED METERS

One of the foundational platform elements of grid modernization necessary to enable customer energy options is the use of advanced meters. The technology of these devices has evolved since the Companies filed their Smart Grid Foundation Project ("SGFP") application in 2016, with the newest generation of commercially available advanced metering combining previous generations' functionality with new levels of integrated grid sensing, computing and open standards communications.

A brief review of the types of meters the Companies use today is instructive when considering future needs. Previous versions of smart metering technology were one of the catalysts for what became known as the *smart grid*, with smart meters communicating over dedicated networks to both send data to and receive data from the utility. These smart meters evolved from an earlier generation of Automated Meter Reading ("AMR"), which were only capable of sending energy usage data to the utility in order to collect billing data.

The new generation of advanced meters has evolved from smart meters to meet the growing trends of customer energy options using the grid. These advanced meters not only

enable the collection of interval usage data and outage notifications, but they also provide better sensing capabilities and needed functionality with remote connect/disconnect capabilities for both residential and commercial customers. This sensing aspect of advanced meters will provide more complete power characteristic measurements and calculations (e.g., voltages and reactive power).[24] The remote connect/disconnect capabilities (traditionally used in the industry to facilitate customer move-in and move-out requests) will potentially reduce the number of outages caused by system stability issues by facilitating targeted curtailment of DER export. These added capabilities with the advanced meters will provide valuable operational data and control; grid operators and distribution planners will better identify, manage and potentially take mitigating action for voltage and frequency issues, which are challenges Hawai‘i faces with the increasing adoption of distributed and bulk-system renewable generation resources.[25]

Moreover, manufacturers of advanced meters have enhanced their devices' internal computer platforms to allow software applications to enable different functionality and capabilities as needs change. The latest generation enables utility software applications that can be downloaded from the meter manufacturer, which has the potential to create an avenue for software development to provide greater responsiveness to future customer and system needs. The software applications installed within advanced meters can enable distributed intelligence for such capabilities as coordination of distribution automation with other field devices, load management for distribution transformers, and detection of electrical faults. This application-

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[24] See A. Ellis et al., *Review of Existing Reactive Power Requirements for Variable Generation* (Nov. 12, 2012) available at http://energy.sandia.gov/wp-content/gallery/uploads/ReviewReactivePower_IEEE_final.pdf.

[25] See Docket No. 2011-0206, *Reliability Standards Working Group – Distribution Circuit Monitoring Program Plan*, filed March 9, 2017, at 11-18. See also Docket No. 2014-0183, *Hawaiian Electric Companies' Power Supply Improvement Plans*, filed December 23, 2016, Appendix O.

based approach to meter functionality enables flexibility and extensibility, and helps mitigate the risk of stranded investment because the software can be readily updated.

2. METER DATA MANAGEMENT SYSTEM

The deployment of advanced meters and the new telecommunications network will require installation of related software systems, including a telecommunications headend (also referred to as a telecommunications gateway), meter headend and MDMS. An MDMS receives data from the advanced meters and serves as the system of record for meter data and configuration information. A core function of the MDMS is to ensure that the data coming from the field is accurate. The MDMS accomplishes this through a set of processes and algorithms known as validation, editing, and estimating ("VEE"), which verifies the meter data. VEE can identify potential data issues within the advanced meter data, such as missing intervals or inconsistent meter reads, that indicate an issue with the meter device or that identify usage patterns that require review or investigation.

Once the advanced meter data is stored within the MDMS, it can be accessed by different systems. Initially, this will include systems integration with the billing module of the Companies' SAP Customer Information System ("CIS")[26] and the DRMS. With advanced meters also able to provide outage notifications and alerts for power quality issues, such as voltage violations, the MDMS will make this type of data available through a report or query; eventually, other new grid modernization systems (e.g., the ADMS) will also access the advanced meter data in real time for both operational/situational awareness and system studies. Moreover, the MDMS is a flexible system that can improve the performance of multiple

[26] See SAP for Utilities Billing and Revenue Management, available at https://www.sap.com/industries/energy-utilities/billing-revenue-management.html.

departments (e.g., load forecasting, revenue protection) within the Companies by providing more granular data to improve forecasts and analysis.

To continue to align with customers' needs, the proposed MDMS will also include the use of a customer energy portal. This portal will provide valuable energy usage information that will provide customers insight to better manage their energy consumption. As the GMS implementation evolves, the Companies anticipate that the customer energy portal will evolve as well, and the features and capabilities provided within it will further enhance the customer experience.

3. TELECOMMUNICATIONS NETWORK

The final platform component of Phase 1 includes a Field Area Network ("FAN") RF-mesh telecommunications network needed to enable the interface of grid-facing field device technologies and customer-facing technologies.[27] This telecommunications network is necessary for the advanced meters to communicate data to the MDMS. However, as described in the GMS,[28] the envisioned telecommunications network infrastructure will also support field devices for distribution system sensing and measurement, operational controls and analytics, and distribution automation. These technologies form the foundational cyber-physical infrastructure necessary for a reliable modern grid. The deployment strategy and process that the Companies are utilizing to proportionally deploy the proposed telecommunications network are further detailed in Exhibit G.

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[27] The GMS identified both a FAN and neighborhood area network ("NAN"). The vendor proposals indicate that the FAN now supports connection to the customer premises such that a technologically distinct NAN is no longer necessary.
[28] See GMS, Section 7.5 (Telecommunications), at 94-97.

The specifications for the Companies' telecommunication network include use cases to take advantage of the potential for distributed coordination and remediation of field devices that can coordinate responses autonomously. Adoption of these advanced technologies will lead to better insight into grid status and more efficient operation, resulting in a grid that is more capable of supporting DER. The telecommunications network serves as the platform to enhance distribution grid operations by providing distribution sensing, control and automation to monitor the distribution grid, as well as tools to mitigate issues, such as excursions from operational standards, when they arise.

As the telecommunications network expands over time to support customer enrollment or participation in customer energy options, managing the network will become more complex. Therefore, a NOC may be needed to monitor and administer the telecommunications system, and the Companies are exploring the current capabilities of the existing/planned infrastructure to support these needs. An application for approval to implement a NOC may be part of a future phase of GMS implementation.

4. SYSTEM INTEGRATION

To maximize the value of the Phase 1 investments, the components must be integrated both together and within the larger ecosystem of the Companies' existing and planned operational systems and business processes. System integration to and between the three proposed systems for Phase 1 is depicted in Figure 3 below and includes:

1) Configuration of the telecommunication solution with the advanced meters, the telecommunications gateway, and the meter headend system;
2) Implementation and configuration of the MDMS to the meter headend system;

3) MDMS system integration with the CIS billing module utilizing a standardized meter data unification system ("MDUS");[29]

4) Making MDMS data available to the DRMS; and

5) MDMS integrated customer energy portal.

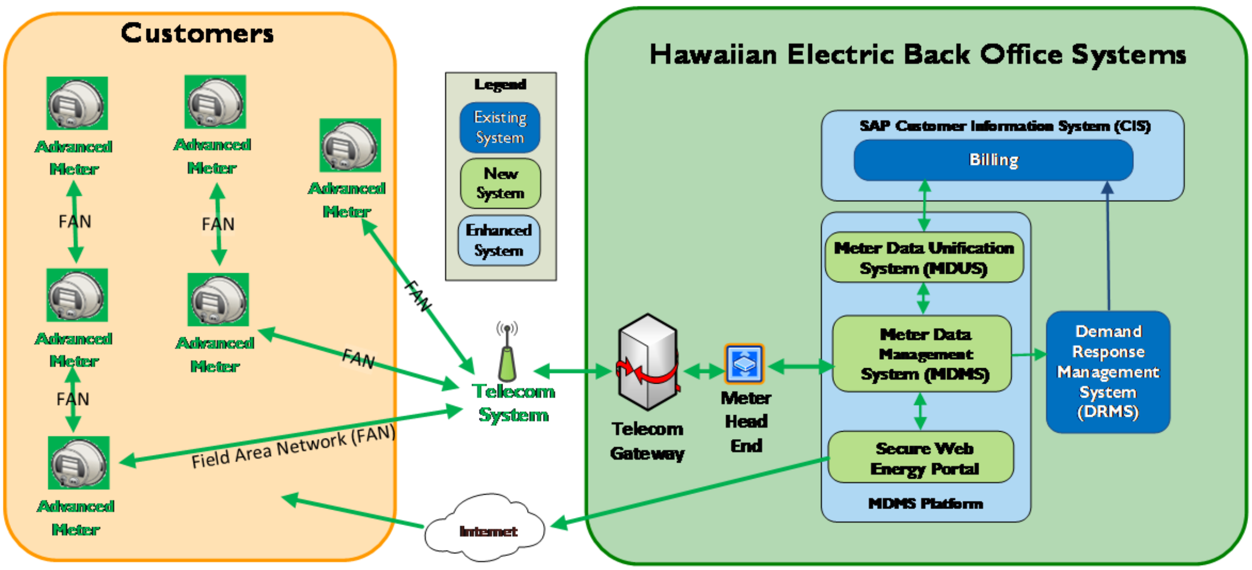

Figure 3

The Phase 1 system integration effort will support billing for the recently-approved Smart Export program, the ability to disconnect CGS+ systems during system emergencies, and the customer-delivered grid services and data exchange via the DRMS. Advanced meters will communicate via the telecommunication solution and utilize a FAN to relay data between devices to a FAN takeout point that directs the data to the telecommunications gateway. The meter data will then be routed to a meter headend system before being entered into the MDMS. The MDMS data will interface with the CIS billing module through the standardized MDUS to enable customer billing. The MDMS will exchange interval data with the DRMS in order to

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[29] See SAP Documentation, *Advanced Metering Infrastructure*, available at https://help.sap.com/erp2005_ehp_05/helpdata/en/eb/75df7f40b741869203c56b5563b415/frameset.htm.

support the development of measurement and verification data by the DRMS. Additionally, customers will be able to access their energy usage information through a customer energy portal.

Grid modernization requires integrated systems that exchange information to manage the grid. Capabilities will increase over time with additional integration between the Phase 2 ADMS component among the DRMS and MDMS to leverage advanced meter data as grid-sensing input for distribution management, outage management, volt/VAR optimization (VVO) and system data analytics.

B. PROJECT BENEFITS

The GMS Phase 1 investments in advanced metering, telecommunications and MDMS provide various benefits as described in the "Benefits of a Grid Modernization Platform" section of Exhibit B. The Companies are proposing to deploy Phase 1 in an as-needed, where-needed manner that will maximize value for customers while minimizing rate impacts. Specifically, this targeted approach is intended to enable and assist in realizing the benefits of all customer energy options.

In particular, the deployment will provide:

- Improved metering functionality and efficiency that will support the recently approved Smart Export, CGS+ and DR Portfolio, as well as enable future customer energy options.

- Advanced metering sensing and control capability that will provide valuable operational data and control; grid operators and distribution planners will be able to better identify, manage, and potentially take mitigating action for voltage and frequency issues that will be fully enabled through the GMS Phase 2 ADMS.

- A customer energy portal to provide customers with insight to better manage their energy usage.

- Deployment of a telecommunication solution to support both advanced metering and field devices that will be further deployed in GMS Phase 2.

This proportional and phased approach not only prioritizes when and where GMS investments should be made, but also mitigates risk by adopting the latest technologies and taking advantage of new advancements over time. As more field devices and advanced meters are deployed, reliability and operational improvements will be realized to the customers' benefit. In short, without these Phase 1 investments, customer energy options will be limited and their respective benefits, and potential for grid services, will not be fully realized.

As discussed below, Phase 1 is expected to be cost-beneficial under a lowest reasonable cost analysis, and when considered in the context of enabling distributed customer energy options that can provide more cost-effective alternatives to traditional wired investments.

C. PROJECT COSTS

As detailed in Exhibits B and H, the Companies estimate that the Capital Costs and Deferred Costs of Phase 1 will total approximately $86.3 million. These costs are planned to be incurred following Commission approval, assumed in 2019, and end in 2023.

The Capital Costs and Deferred Costs include costs for: (1) internal labor; (2) materials; (3) outside services; (4) other; (5) overheads; and (6) AFUDC, as described in the "Expected Investments" section of Exhibit B. These include costs for products and services to be supplied by third-party vendors. As detailed in Exhibit E, the Companies are obtaining vendor responses through their formal RFP process. As of the filing of this Application, the Companies have issued RFPs for the advanced meters; MDMS and FAN-based telecommunications network, and have down-selected vendors for each component. However, the Companies have not yet formally selected the final vendor for any individual component of Phase 1. Additional information on the Companies' process for final selection and the expected timeline for award is provided in Section I (*RFP Process*) of Exhibit E.

D. COST-BENEFIT CHARACTERISTICS

As noted in the GMS Phase 1 Business Case, it is impracticable to aggregate GMS implementation benefits for use in a traditional cost-benefit analysis.[30] GMS investments have interrelated and naturally synergistic functions that make it infeasible to determine the cost-effectiveness of each GMS component independently. This difficulty is compounded by prior decisions in other dockets (e.g., DR and DER) where benefits were determined separate from the GMS and using different methods and assumptions. Recognizing this, in the GMS, the Companies proposed a holistic cost-effectiveness framework for evaluating the Companies' grid modernization efforts.[31] Under this framework, the Phase 1 advanced metering, headend, MDMS, and telecommunications components would all be analyzed using the lowest reasonable cost evaluation methodology.[32]

Here, the competitive procurement process for the Phase 1 components required the Companies to evaluate and consider alternative technology options to meet GMS policy objectives. As described in Exhibit E, the Companies issued RFPs encompassing the major components of Phase 1, including advanced metering, headend, MDMS, and telecommunications. All of the RFPs were developed and evaluated in context with one another and the Companies' broader initiatives, including support of the recently-approved DER programs and enterprise-level initiatives. The evaluation of the RFPs includes vendor demonstrations, testing and assessment to ensure the solutions proposed in each RFP are compatible with each other and consistent with the GMS to ensure that the technology is scalable and compatible in the future to minimize risks of stranded investments. Implementation risk and

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[30] See Exhibit B, attached hereto.
[31] See GMS, Section 4.2 (Cost-Effectiveness Framework).
[32] See Exhibit B, attached hereto.

cost considerations are also being taken into account for each potential combination of vendor solutions. The solutions obtained through this competitive procurement process will satisfy the Companies' technology needs (aligned to customer and policy objectives) at the lowest reasonable cost. Stated differently, it is prudent and necessary for the components presented in Phase 1 to be implemented into the Companies' electric grid at this time in order to achieve the benefits identified in the various DR and DER decisions, in addition to contributing to the Companies' ability to achieve the State's RPS and EoT goals.

As noted in the GMS and Exhibit B, the need for a new holistic evaluation framework has also been recognized in other jurisdictions addressing grid modernization.[33] In particular, the California Public Utilities Commission ("CPUC") has an ongoing proceeding examining, among other things, the valuation of customer benefits for grid modernization investments. The CPUC examined four potential options for evaluating the cost-effectiveness of proposed grid modernization investments: (1) utilize existing methods, such as customer outage minutes; (2) develop a benefit-cost methodology for grid modernization; (3) apply a least-cost/best-fit framework; or (4) assess net benefits as a component of the Integrated Resource Plan ("IRP") optimization analysis. The CPUC concluded that Option 2 (the proposal to develop a grid modernization cost-effectiveness [benefit-cost] methodology) is not realistic.[34] The CPUC further stated that the benefits of each grid modernization investment cannot be isolated from the benefits provided by the other grid investments and must be evaluated within the context of the

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[33] See GMS, Appendix C, Section 2 (*Literature Review of Grid Modernization Evaluation Methodology in other Jurisdictions*).

[34] See CPUC, Rulemaking 14-08-013 Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769, *Decision on Track 3 Policy Issues, Sub-Track 2 (Grid Modernization)*, D.18-03-023 issued March 26, 2018 (effective March 22, 2018), at 24-25, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M212/K432/212432689.PDF.

overall cost-effectiveness of the DERs. The CPUC decision is also complimentary with the Department of Energy Distribution System Platform (DSPx) decision guide and cost-effectiveness framework which outlines recommended application of least-cost / best fit method, traditional customer benefit-utility cost, integrated power system & societal benefit-cost and real option analysis approaches for grid modernization investments.[35]

As discussed in Exhibit B, similar to the lowest reasonable cost framework proposed by the Companies in the GMS, Option 3 (the least-cost/best-fit) methodology under the CPUC and DSPx framework would apply to the Phase 1 Application. Moreover, similar to the approach taken by the CPUC in California, the Companies propose that the cost of Phase 1 of the GMS should be evaluated in consideration of the collective benefits derived from customer energy options described above.

E. <u>ANTICIPATED IMPLEMENTATION SCHEDULE</u>

As previously noted, the Companies plan on pursuing a deliberate phased approach to their GMS implementation. This proportional deployment will incrementally roll out systems and technologies to build capability, functionality and coverage to support customers' expectations and need while also addressing system requirements. This approach will also reduce risks associated with stranded assets and technology obsolescence, while incrementally making investments to progressively implement the vision articulated in the GMS.

Figure 4 below provides a high-level view of the anticipated Phase 1 deployment, beginning in 2019 and ending in 2023 (or early 2024 depending on when Commission approval is received).

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[35] <u>See</u> Department of Energy Office of Electricity, *Modern Distribution Grid (DSPx) Decision Guide Volume III*, Section 3.4.1 Cost-Effectiveness Framework, June 28, 2017, <u>available at</u> https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

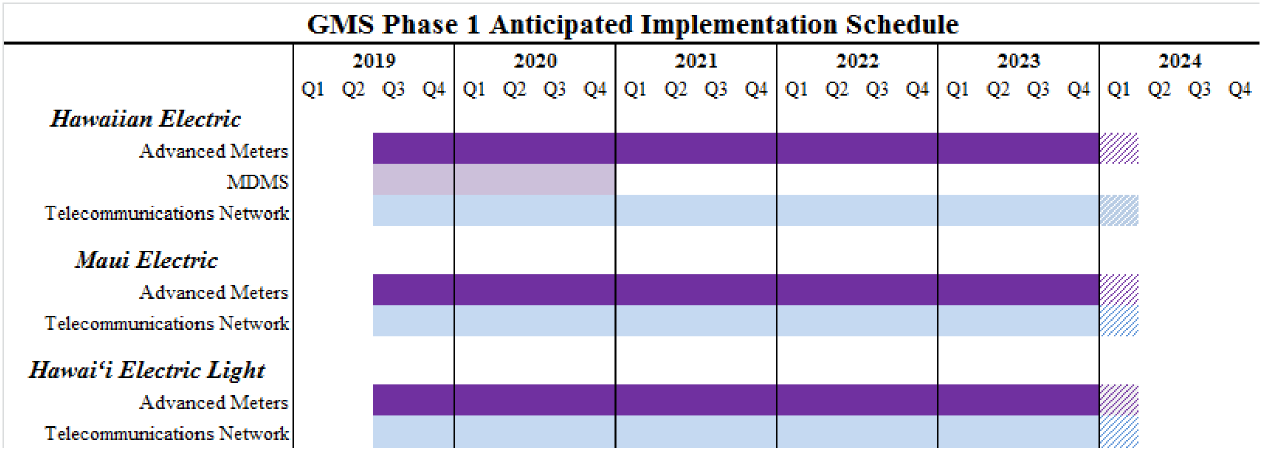

Figure 4

The Companies are proposing a modern grid that aligns advanced meter costs incurred with the value derived for customers through customer energy options while providing flexibility to adopt new technologies over time. Advanced metering will support recently-approved DER programs and the DR Portfolio, as well as future customer energy options. Additionally, the Companies anticipate adoption of advanced metering as the new standard for metering during the GMS implementation. Therefore, GMS Phase 1 will deploy advanced meters to support new meter sets and replacement meters as well as to enable customers participating in the recently-approved Smart Export and CGS+ DER programs[36] and the DR Portfolio.[37] The forecasted number of meters deployed in Phase 1 is based on historic counts for annual meter installations as well as anticipated customer participation in Smart Export, CGS+ and other customer energy options. Actual meter deployment is contingent upon the number of new meter sets, replacement meters, and participation in Smart Export, CGS+ and DR. The advanced meter costs are based on unit cost estimates derived from responses in the advanced meter RFP and meter counts are largely based on forecasted customer enrollment in customer energy options.

[36] See D&O 34924.
[37] See Docket No. 2015-0412, D&O 35238, issued January 25, 2018.

It is possible that new programs that also require advanced meters will be introduced in the 2019-2023 timeframe. Because the Companies cannot predict future customer energy options, this Application includes costs for the advanced meters identified in the GMS that are required to support known DER programs and DR Portfolio. However, the cost estimate for this portion of the Application is highly variable based on customer enrollment and participation in customer energy options. Therefore, the incremental cost for these programs should be taken into account when evaluating overall program costs and benefits.

The GMS is deploying advanced metering via an "opt-in" approach, which is in contrast to prior applications by the Companies that sought to deploy advanced meters to all customers. Going forward, the Companies recommend that program-specific costs, such as advanced meters, be included in the program-specific dockets. The DR and DER dockets were initiated during a period when it was anticipated that SGFP was going to deploy advanced meters to all customers and therefore the costs were not included in those dockets. With the inception of the GMS as the Companies' enabling platform, the advanced metering costs to enable the CGS+, Smart Export and DR Portfolio were included in the GMS Phase 1. Because advanced meters are required to enable customer participation in these customer energy options, the advanced meter deployment forecast and associated cost in this Application have inherent variability due to program adoption by customers. Therefore, advanced meter costs to enable future customer energy options beyond this Application should be addressed in each respective docket. The exception to this is the cost for advanced meters that are installed for new customer service requests or replacements, since the advanced meter will be the new meter standard going forward.

The Companies have a history of exploring and implementing new technologies that drive efficiency, as illustrated by the multiple metering platforms that are currently being utilized and supported (i.e., PLC, AMR, MV-90,[38] and electromechanical).[39] Because each of these meter device types is approaching their end-of-life, business decisions will need to be made to replace these systems at some point in the future. Ultimately, the Companies aim to simplify the metering platforms to a common tri-company process and solution. As advanced meters are deployed consistent with customer adoption and as old meters are retired or replaced, a critical mass of customers will eventually have advanced meters installed such that the old meters are no longer cost-effective to maintain and read manually. At that point, the Companies will continue to evaluate their approach toward completing the deployment of advanced meters.

As shown in Table 1 below, the recently-approved CGS+ and Smart Export programs and DR Portfolio will be operationalized prior to GMS Phase 1 and therefore require deployment of an interim metering solution to meet the technical requirements of enabling these programs, as directed by the Commission.[40]

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[38] Itron's meter data collection and processing application.

[39] Each of these meter types are currently deployed through the Companies' territories to accommodate inaccessible properties, customer billing needs, or as part of older meter installations that predate the deployment of advanced meters.

[40] See D&O 34924.

Initiative	**2018**	**2019**	**2020**
Initial Grid Modernization Application	• GMS Phase 1 Procurement o Telecommunications o Advanced meters o Meter data management system • GMS Phase 1 Regulatory application	• GMS Phase 1 Regulatory approval • Initiation of system implementation o Telecom o MDMS • Proportional deployment o GMS advanced meters for new enrollments in Smart Export, CGS+, and DR Portfolio o Telecom components	• Complete systems integration o Telecom o MDMS o MDMS to CIS • Proportional deployment o GMS advanced meters for Smart Export, CGS+, DR Portfolio, replacement meters, and new meter sets o Telecom components
DER Programs	• Implementation o CGS+ o Smart Export • Deployment o Interim “smart production/net meter” solution	• Deployment o Transition from interim “smart production/net meter” solution to GMS advanced meters o GMS advanced meters for new enrollees	• Deployment o GMS advanced meters for new enrollees
DR Programs	• Regulatory approval of new DR rate structures, riders and grid service tariffs • Implementation of demand response management system • Contract execution with Grid Service aggregators • Initial customer enrollment and enablement • Deployment • Interim metering solution	• Ongoing customer enrollment and enablement • Second RFP for additional grid services procurement • DRMS Go-live • Deployment o Interim metering solution	• Deployment o GMS advanced meters for new enrollees

Table 1

While evaluating interim solutions needed to implement customer energy options in advance of Phase 1 approval, the Companies will work to minimize stranded investments and costs inherent with these solutions. However, if costs of the interim solutions are significant, separate application(s) may need to be filed to address cost recovery for interim solutions.

The MDMS component of Phase 1 is anticipated to take approximately 15 months following Commission approval and will include a customer energy portal (see Exhibit B). To explore enabling advanced metering capabilities soon after receiving Commission approval, the Companies requested information on a hosted software-as-a-service (“SaaS”) MDMS hosted

solution from the MDMS providers with the ability to transfer the MDMS data to the Companies' on-premises MDMS once implemented. Based on review of the proposals, the SaaS solution proved to be more costly in the long term compared to an on-premises solution and did not appear to expedite the system integrations at the core value of the MDMS solution. The Companies will continue to evaluate these options to meet customer needs and program demands.

As further described in Exhibit B, the FAN-based telecommunications network will be proportionally deployed to support deployment of the advanced meters and field devices for distribution sensing, control and automation. If a single customer or several customers in a certain area enroll in customer energy options, then a cellular data connection to the FAN may be the most economic approach to communicate with those meters. In other areas with more densely clustered advanced meters and/or need for distribution field devices, alternative communications with higher bandwidth and lower latency will be explored. Because of the engineering planning associated with designing and deploying a scalable FAN-based telecommunications network, the details regarding the Companies' proposed deployment strategy considerations are included in Exhibit G.

Phase 1 of the GMS will create the necessary platform for current and future customer energy options and grid needs to help the Companies realize the State's RPS goals. As described in the GMS, Phase 1 incorporates technologies that will allow for the expansion of additional levels of renewable generation through the programmatic and systemic interconnection with Commission-approved DER and DR programs. Additionally, Phase 1 will provide the basis for future GMS deployments, such as ADMS and other field devices, necessary to increase grid efficiency and resiliency while continuing to grow customer options and utility-based program

opportunities, such as EoT and EV expansion in Hawai'i. Therefore these GMS Phase 1 investments serve to enable a sustainable and clean energy future for Hawai'i.

X. ACCOUNTING AND RATEMAKING TREATMENT

The Companies are requesting approval of \$86.3 million for the Capital Costs and Deferred Costs for the Phase 1 implementation. The accounting and ratemaking treatment proposed to be applied to Phase 1 is detailed in Exhibit C. Phase 1 of the GMS is comprised of three main interrelated components consisting of traditional capital expenditures, deferred software expenses and internal expense elements, necessary for a smooth, cost-conscious deployment.

A. ACCOUNTING TREATMENT

The proposed accounting for the interrelated Phase 1 components generally follows the accounting for capital expenditure and software projects approved by the Commission in the past. In general, the cost of equipment and hardware will be capitalized and depreciated based on depreciation rates in place at the time of this filing, while software and related development costs will be deferred, and amortized over a twelve-year period. Such treatment is in accordance with Generally Accepted Accounting Principles ("GAAP") and consistent with the Companies' current accounting for such costs. Costs related to software development for Phase 1 and system integration work will follow the Companies' existing accounting policy, which is consistent with the Financial Accounting Standards Board's ("FASB") Accounting Standards Codification ("ASC") 350-40, "Internal-Use Software."[41] The Companies will incur some Expense Costs; however, these costs are not included for recovery in this Application. To the extent that these

[41] Formally known as Statement of Position 98-1, "Accounting for the Costs of Computer Software Developed or Obtained for Internal Use," issued in March 1998.

costs are not recovered in current rates, the Companies plan to address recovery of these costs in future rate cases. The proposed accounting for each of the platform components of Phase 1 is described in Exhibit C.

B. INTERIM RECOVERY

As requested above, the Companies are seeking to recover of the Capital Costs and Deferred Costs of Phase 1 through the MPIR Mechanism until base rates that reflect the revenue requirements associated with those costs take effect in a future rate case for each respective company.

The purpose of the MPIR is to provide a mechanism for recovery of revenues for net costs of approved "Eligible Projects" placed in service between general rate cases that are not provided for by other effective tariffs.[42] As noted in Exhibit D, the Companies maintain that Phase 1 qualifies as an eligible project under Sections III.B.1(b) (projects that make it possible to accept more renewable energy); III.B.1(c) (projects that encourage clean energy choices and/or customer control to shift or conserve their energy use); III.B.1(d) (approved or accepted plans, initiatives, and programs); and III.B.1(f) (grid modernization projects), of the MPIR Guidelines. In addition, as further discussed in Exhibit D, the instant Phase 1 application, including the attached business case (see Exhibit B), satisfies the criterion set forth in the MPIR Guidelines. A detailed illustrative MPIR calculation for Phase 1 is provided in Exhibit J.

In the alternative, as discussed in Exhibit D, if the Commission is not inclined to allow the Companies to recover the Deferred Costs of Phase 1 through the MPIR Mechanism then the Companies request approval to recover the Deferred Costs through the REIP Surcharge until

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[42] See Docket No. 2013-0141, Order No. 34514, issued April 27, 2017, Attachment A (MPIR Guidelines), Section II.A.1.

base rates that reflect the revenue requirements associated with the Deferred Costs take effect in a future rate case for each respective company. If the Commission is not inclined to allow REIP recovery, then the Companies request approval to recover the Deferred Costs through a future rate case for each respective company, with amortization of the Deferred Costs commencing when base rates that reflect the Deferred Costs take effect in those respective proceedings.

C. BILL IMPACT

As shown in Exhibit I, the Companies estimate that the average monthly bill impact of Phase 1 of the GMS for a typical residential customer using 500kWh would be:

- $0.24 at Hawaiian Electric, ranging from $0.01 to $0.59;
- $0.34 at Maui Electric, ranging from $0.05 to $0.87; and
- $0.55 at Hawaiʻi Electric Light, ranging from $0.05 to $1.18.

The bill impacts shown above reflect a 30 year period for Phase 1. The bill impact excludes Phase 2 and other future replacement costs. Beyond Phase 1 (2023), the Companies will need to continue to invest in and modernize the grid. At this time the scope and scale of this future effort are not known. Technology is evolving at a rapid pace. As a result, the Companies will need to assess the needs of the customers and the grid in order to pair the appropriate technology that is available. Replacements will be included in future filings or rate cases.

XI. CONCLUSION

Wherefore, the Hawaiian Electric Companies respectfully request a decision and order approving:

(1) Implementation of the proposed Phase 1 of the GMS (at a total current estimated cost of $86.3 million);

(2) A commitment of funds in excess of $2.5 million for the Capital Costs of Phase 1, pursuant to Paragraph 2.3(g)(2) of G.O. 7;

(3) The proposed accounting and ratemaking treatment for Phase 1, including:

(a) Deferral of the Deferred Costs of Phase 1, pursuant to the Companies' Software Accounting Policy and D&O 18365;

(b) Accrual of AFUDC, as appropriate, during the applicable construction periods of the Phase 1;

(c) Recovery of the Capital Costs and Deferred Costs through the MPIR Mechanism until base rates that reflect the revenue requirements associated with the Capital Costs and Deferred Costs of Phase 1 take effect in a future rate case for each respective company, provided however that if the Commission is not inclined to allow the Companies to recover the Deferred Costs through the MPIR Mechanism, then in the alternative, the Companies request approval to recover the Deferred Costs through:

(i) the REIP Surcharge, until base rates that reflect the revenue requirements associated with the Deferred Costs take effect in a future rate case for each respective company; provided further that if the Commission is not inclined to allow recovery of the Deferred Costs through either the MPIR Mechanism or REIP Surcharge, then the Companies propose to recover the Deferred Costs through;

(ii) a future rate case for each respective company, with amortization of the Deferred Costs commencing when base rates that reflect the Deferred Costs take effect in those respective proceedings; and

(4) Such other and further relief as may be just and equitable in the premises.

DATED: Honolulu, Hawai'i, June 21, 2018.

HAWAIIAN ELECTRIC COMPANY, INC.
HAWAI'I ELECTRIC LIGHT COMPANY, INC.
MAUI ELECTRIC COMPANY, LIMITED

By ______________________

Joseph P. Viola
Vice President, Regulatory Affairs
Hawaiian Electric Company, Inc.

Vice President
Hawai'i Electric Light Company, Inc.
Maui Electric Company, Limited

VERIFICATION

STATE OF HAWAI'I)
) ss.
CITY AND COUNTY OF HONOLULU)

JOSEPH P. VIOLA, being first duly sworn, deposes and says: That he is Vice President, Regulatory Affairs, of Hawaiian Electric Company, Inc., and Vice President of Hawai'i Electric Light Company, Inc. and Maui Electric Company, Limited, Applicants in the above proceeding; that he makes this verification for and on behalf of said Applicants, and is authorized so to do; that he has read the foregoing Application, and knows the contents thereof; and that the same are true of her own knowledge except as to matters stated on information or belief, and that as to those matters he believes them to be true.

Joseph P. Viola

DEBORAH ICHISHITA ★ NOTARY 04-409 PUBLIC ★ STATE OF HAWAII

Subscribed and sworn to before me this 21st day of June, 2018.

Deborah Ichishita

DEBORAH ICHISHITA

Notary Public, First Circuit,
State of Hawai'i

My Commission expires July 18, 2020

STATE OF HAWAI'I NOTARY CERTIFICATION

Doc. Date: 6/21/2018 # of pages 215

Notary Name: DEBORAH ICHISHITA First Circuit

Doc. Description: Verification for Application, Exhibits A-L

Deborah Ichishita 6/21/18

Notary Signature Date

DEBORAH ICHISHITA ★ NOTARY 04-409 PUBLIC ★ STATE OF HAWAII

Exhibit A

GMS Phase 1 Application

Grid Modernization Strategy Working Plan

Note: References to exhibits in this document refer to exhibits included in the accompanying application unless otherwise noted.

GRID MODERNIZATION STRATEGY WORKING PLAN

On August 29, 2017, the Hawaiian Electric Companies[1] filed their final Grid Modernization Strategy ("GMS")[2] with the Hawaiʻi Public Utilities Commission ("Commission") following several months of stakeholder engagement and a public comment period. The GMS provides near- and long-term plans for the Companies' proposed design to deploy advanced technologies and back office systems that will integrate new technologies and processes with the existing infrastructure to update the electric grid, which will pave the way for the Companies to achieve Hawaiʻi's 100% RPS goal by 2045.[3] Following Commission approval of the GMS, the Companies are now moving forward with their submission of supporting applications that align with the program descriptions provided in the August 29th filing.[4] In adherence with Order No. 35268, this ten-page GMS Working Plan offers further context on how the Companies intend to implement the GMS, the expected outcomes of each application, the interdependencies between each application, and the expected time frame for when the Companies intend to submit each subsequent application to the Commission for approval.

The Companies are dividing the implementation of the GMS into multiple phases, beginning with the submission of the accompanying Phase 1 ("Phase 1") Application ("Application"). Each phase will build and expand the existing electric grid into a modernized one with a logical progression of features and functionality. The maturity of the different components of grid modernization,[5] as well as the prioritized need for the functionality and capabilities of each component, are driving the order and sequencing for each phase of the implementation. Subsequent phases will layer additional technologies to further evolve the grid, adding advanced operational capabilities at a pace that will meet customer needs and create customer value while remaining flexible to adopting emerging technologies. This proposed phase and proportional deployment strategy will also have the added benefit of reducing implementation risks for the Companies by incurring associated costs over time—rather than making an initial large investment, as proposed in the Smart Grid Foundation Project[6]—which will help to reduce the bill impact for customers throughout the project. Further details regarding the anticipated average bill impact expected from Phase 1's implementation for each respective utility is provided in Exhibit B (*Project Justification with Business Case Support*).

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[1] Hawaiian Electric Company, Inc., Hawaiʻi Electric Light Company, Inc., and Maui Electric Company, Limited, are collectively referred to as the "Hawaiian Electric Companies" or the "Companies."
[2] See Docket No. 2017-0226, *Modernizing Hawaiʻi's Grid For Our Customers*, filed August 29, 2017.
[3] See Hawaiʻi State Energy Office, Grid Modernization, Renewable Portfolio Standard ("RPS") targets, available at http://energy.hawaii.gov/renewable-energy/grid-modernization.
[4] See Docket No. 2017-0226, Decision and Order No. ("D&O") 35268, issued February 7, 2018.
[5] See the U.S. Department of Energy's Next Generation Distribution System Platform, Volume II, *Advanced Technology Maturity Assessment*, available at: http://doe-dspx.org/sample-page/dspx-volumes/ ("DOE Advanced Technology Maturity Assessment").
[6] See Docket No. 2016-0087, *Exhibit B - Business Case*, filed March 31, 2016.

I. GMS IMPLEMENTATION SCHEDULE

As noted above, the Companies are proposing multiple phases for their GMS implementation, which is depicted in Figure 1. Phase 1 includes investments in advanced meters, a Meter Data Management System ("MDMS"), and a Field Area Network ("FAN")-based telecommunications network. Deployment of these three initial components associated with Phase 1 aligns with existing needs to support recent Commission decisions, such as the approved Distributed Energy Resource ("DER") and Demand Response ("DR") Portfolio.[7] Furthermore, these three components will enhance potential dynamic pricing options the Commission is currently considering, such as Time-of-Use ("TOU") programs, which will require interval usage data for tariff calculations made possible through the use of the proposed advanced meters and the MDMS platform.[8]

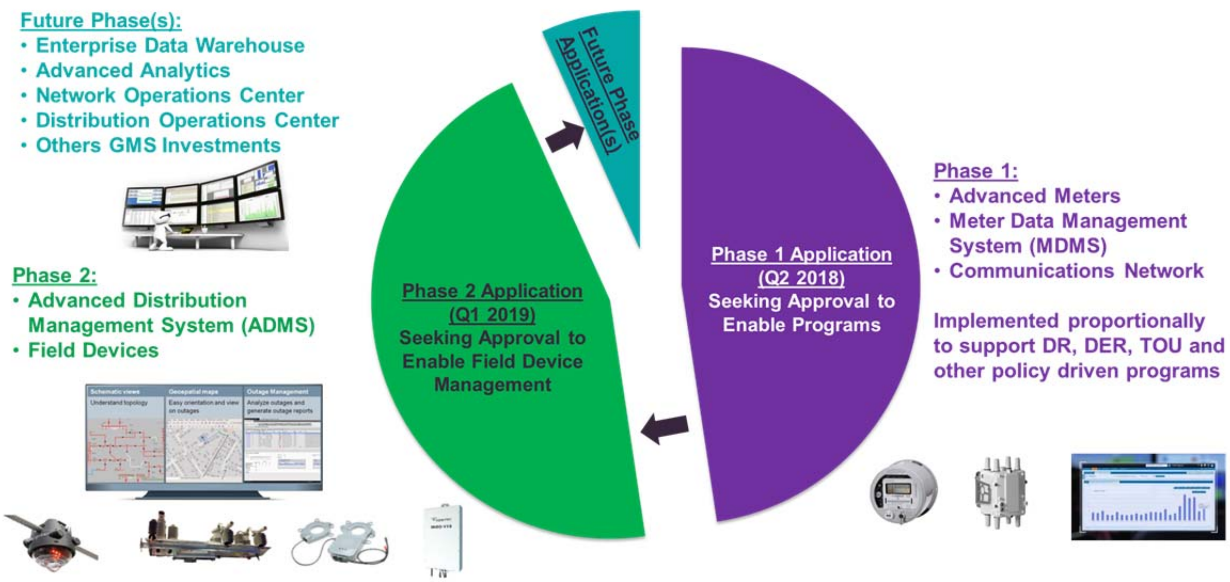

Figure 1

As part of the GMS's second implementation phase ("Phase 2"), the Companies will propose an Advanced Distribution Management System ("ADMS") and field devices to enable enhanced grid control, visibility, and data aggregation functionalities. The Companies anticipate submitting the Phase 2 application to the Commission by early 2019, which will build upon the components and technologies introduced as part of Phase 1. Additionally, the telecommunications network deployed as part of Phase 1 will deliver the communications

[7] See generally Docket No. 2014-0192 (DER) and Docket Nos. 2015-0411 and 2015-0412 (DR). The DER and DR programs require advanced metering to record interval usage data for tariff calculation of the Smart Export program, measurement and verification for DR incentive payment calculation, and a remote service switch to curtail Customer Grid-Supply Plus ("CGS+") energy export when system stability is at risk. The Companies are implementing an interim metering solution to enable the required controls for initial CGS+ customers in advance of the GMS Phase 1 implementation of advanced metering and MDMS. Additionally, the DR dockets provide for the demand response management system ("DRMS") and the portfolio of DR programs. The DRMS will rely on the DR aggregator data in advance of revenue quality metering data from the advanced metering for the measurement and verification of DR performance and the associated incentive payment calculation that support the current and future DR programs.
[8] See Docket No. 2014-0192, Order No. 33923, issued September 16, 2016.

platform necessary for future field devices and advanced meters to provide the grid sensing capabilities and data needed by the ADMS.

The scope for future phases of the GMS implementation will be informed by an assessment of required supporting capabilities, including expanded data management, a field network operations center ("NOC"), and enhanced operational human-machine interfaces for distribution operators. Additionally, expansion of the MDMS-incorporated online customer energy portal may be needed in the future as more customers receive advanced meters, and operational analytics capabilities beyond what is provided by the MDMS and the ADMS may lead to additional technologies being requested for subsequent GMS implementation phases in the future. The Companies anticipate that an application associated with any future projects beyond Phase 2 of the GMS may be submitted to the Commission in the 2020 time frame, depending on the scope and timing for investments in these grid modernization components and in coordination with broader enterprise systems planning processes that the Companies may be undertaking in the future.

To ensure adequate maturation of future functional and technological needs, the Companies' Request for Proposals ("RFPs") activity associated with each phase of the GMS implementation will be timed to provide an informed budgetary estimate of the funding required. Subsequently, with the Commission's consideration of each phase's funding application, the Companies will conduct due diligence and negotiations to determine final vendor selection for the grid modernization solutions that best meet the needs of the GMS while taking into consideration the bill impact to customers. Conducting these concurrent purchasing and RFPs selection processes will result in more streamlined implementations than if the processes were conducted sequentially.

II. PHASE 1: ADVANCED METERS, METER DATA MANAGEMENT SYSTEM AND TELECOMMUNICATIONS NETWORK

The Companies have been working to develop detailed grid architecture as well as functional requirements through use-cases to identify and document system requirements; information flows, and interfaces while also identifying associated Companies-specific business process changes that utilize the new systems and capabilities.[9] This technique is a classic "people, process, and technology" impact analysis employed to successfully manage technology projects. The advanced meter and telecommunications network RFPs were issued in December 2017, with the MDMS RFP following closely in early January 2018. The RFPs were based on these established grid architecture and functional use-case requirements (see Exhibit G – *Telecommunications Network Considerations*). Evaluation of the resulting proposals is ongoing and will include further review and testing in parallel with the Commission's consideration of the accompanying Application. Performing the planning, preparation, and due diligence up front reduces the risks associated with procurements and helps to ensure vendor and solution selections that are aligned with the GMS.

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[9] The Companies have leveraged existing use-cases in order to adopt industry best practices that are also incorporated into system requirements for GMS systems. This approach reduces the need for customization as the electric utility industry progresses toward similar requirements through common use-cases. See Electric Power Research Institute's *Smart Grid Resource Center*, available at http://smartgrid.epri.com/Repository/About.aspx.

The goal of Phase 1 is to implement three fundamental platform investments: (1) advanced meters with integrated communications; (2) an MDMS, which is the system of record for advanced metering data and configuration; and (3) an interoperable, scalable telecommunication network to enable the communication path for both the advanced meters and the future ADMS's field devices. These three key components are part of a modern grid platform (i.e., the grid the Companies need) that will provide immediate value to customers and will continue to bring additional value as subsequent phases are deployed.

The advanced meters, MDMS, and telecommunications network backbone are being pursued first for a variety of reasons, including the following: (1) the advanced meters and MDMS are needed to enable recently approved DER programs and the DR Portfolio,[10] anticipated future programs like TOU,[11] and other DER programs that progress toward the Commission's vision for a robust DER market;[12] and (2) these investments align with building a platform for a proportional, flexible, and scalable approach for grid modernization with discrete and manageable phases. Most importantly, Phase 1 is the logical first step to support existing energy policies and customer-owned energy resources toward achieving Hawai‘i's RPS goals.

A. ADVANCED METERS

Advanced meters are one of the key platform elements of grid modernization in Hawai‘i. The communication capabilities in advanced meters provide the data that enables customers to obtain visibility into their energy usage through an MDMS-integrated energy portal both before and after their electricity bill arrives. These meters have evolved technologically; with the latest generation of commercially available advanced meters combining the functionality of previous generations with new levels of integrated grid-sensing, computing, and open standards communications (see Exhibit B). Advanced meters record interval usage data, provide outage notifications, and enable remote service switch capabilities similar to prior generations of smart meters and also provide better sensing capabilities, including more complete power characteristics for both residential and commercial customers.

As part of the GMS, the Companies plan to initially deploy advanced meters to those customers who choose to enroll in customer energy options[13] that require the technological capabilities provided by these devices. More specifically, the advanced meters will be deployed to customers who enroll in existing DER programs (i.e., Customer Grid Supply Plus (CGS+) and Smart Export) that require complex billing and credit calculations for these programs and/or require measurement and verification calculations for DR program incentives. Because the Companies anticipate continuing expansion of customer energy options, the Companies expect to make advanced meters the new meter device standard, meaning that advanced meters will begin

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[10] See Docket No. 2014-0192, D&O 34924, issued October 20, 2017; Docket No. 2015-0412, D&O 35238, issued January 25, 2018.
[11] See Docket No. 2014-0192, Order No. 33923, issued September 16, 2016.
[12] See Docket No. 2014-0192, D&O 34924, issued October 20, 2017, at 7.
[13] The term "customer energy options" as utilized in this Application is inclusive of existing and new tariffs and/or programs including DR Portfolios (including TOU and future dynamic pricing) and DER programs. All of these options would be inclusive of any customer-sited resources, including but not limited to photovoltaic ("PV"), distributed storage, and electric vehicle ("EV").

to be deployed for new customer service requests and meter replacements in the future. Details of the Companies' projected advanced meter deployment schedule as part of Phase 1 is provided in Exhibit B.

Based on stakeholder feedback, the Companies realize that not all customers will want to have a wireless communicating advanced meter installed at their premises due to perceived health, safety, or privacy concerns. To offer customers additional options, the Companies are exploring wired communications alternatives for advanced meters, such as Power Line Carrier communication.[14] However, the use of advanced meters is a precondition to participation in certain specified DER and DR programs because manually read metering cannot support the increasing complexity of the rates and incentives for these programs (see Exhibit B for a detailed explanation of the issues involved in manual interval meter reading). Therefore, some customers may need to understand the program-enabling metering requirements (as detailed by the Companies) before choosing to participate in these programs.

B. METER DATA MANAGEMENT SYSTEM

The deployment of advanced meters will require the installation of related hardware and software to store, analyze, and manage the meter data. The MDMS is the system of record for meter configuration as well as meter data. A core function of the MDMS is to perform "validating, editing, and estimating" ("VEE") with algorithms to ensure meter data accuracy. VEE can identify potential data issues within the meter data, such as missing intervals or inconsistent meter reads, which may indicate an issue with the advanced meter or the telecommunications network, as well as identify usage patterns that require review or investigation.

The MDMS is a key component in a collection of systems that will comprise Hawai'i's modernized grid. As noted in Exhibit B, the Companies' proposed MDMS will supply the following capabilities: (1) providing data to the billing module of the Companies' SAP Customer Information System ("CIS")[15] through a standardized Meter Data Unification and Synchronization system[16] to enable rate calculation for more complex tariffs (e.g., CGS+, Smart Export, TOU, and DR); (2) hosting or interfacing with a secure online energy portal for customers to access and review their electricity usage; (3) enabling remote connectivity features to support remote connect and disconnect for move in, move out, and system stability curtailment of CGS+; and (4) providing a repository of data recorded by advanced meters to enable analytics and insights for planning, forecasting, revenue protection, and operations, such as highlighting outage or voltage problem areas.

As further described in Exhibit B, access to energy usage data is a key part of enabling customer choice and control. Therefore, an online customer energy portal with a standardized

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[14] See DOE Advanced Technology Maturity Assessment, page 49.
[15] See SAP for Utilities Billing and Revenue Management, available at https://www.sap.com/industries/energy-utilities/billing-revenue-management.html.
[16] See SAP Documentation, *Advanced Metering Infrastructure*, available at https://help.sap.com/erp2005_ehp_05/helpdata/en/eb/75df7f40b741869203c56b5563b415/frameset.htm.

Green Button[17] interface and functionality will be needed for customers and customer-authorized third parties[18] to access the meter data collected from the advanced meters and stored in the MDMS. In the near term, the Companies are exploring the utilization of online customer energy portals that are already integrated with the MDMS. This approach will provide basic functionality for energy data access for customers that receive advanced meters. The need and capabilities of a customer-focused online energy portal are likely to evolve as the number of customers with advanced meters installed expands. The Companies will assess customer utilization and feedback regarding the Phase 1 online customer energy portal to understand customer preferences and to plan the future evolution of the portal for future phases of the GMS implementation.

The Companies' proposed MDMS will also facilitate meter data analytics, both within the MDMS platform (such as VEE) and by way of meter data export for analytics and action by other systems (such as LoadSEER[19]) or for planning purposes. Also, as more customers receive advanced meters, the Companies' load forecasts and load research can be refined with this higher resolution data.

Further details regarding the anticipated implementation schedule for the MDMS is provided in Exhibit B.

C. TELECOMMUNICATIONS NETWORK

The Companies' planned telecommunications network is a fundamental component to grid- and customer-facing technologies that will provide customers with the safe, secure, reliable and efficient operation of a modern electric grid system. Unlike prior generation telecommunication networks for smart meters, the proposed FAN-based approach will support a range of sensing, control, and automation uses today and into the future. This includes advanced meters as well as future field devices, both of which will provide distribution sensing and measurement, operational controls and analytics, and some distribution system automation. Additionally, a network management system is needed to monitor, manage, and control the FAN utilizing both software and hardware. These communications technologies are part of the foundational cyber-physical grid[20] infrastructure and will lead to more efficient grid operation and utilization of customer energy options.

To support both interoperability and extensibility, the GMS employs a standards-based approach to grid modernization technologies, which the Companies recognize as crucial requests

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[17] See Green Button Alliance, available at http://www.greenbuttondata.org/.
[18] See North American Energy Standards Board (NAESB) REQ.21, *Energy Services Provider Interface for Green Button*, available at https://www.naesb.org/ESPI_Standards.asp.
[19] LoadSEER is utilized by the Companies for distribution planning analytics. See http://www.integralanalytics.com/products-and-services/spatial-growth-planning/loadseer.aspx.
[20] As stated by the National Institute of Standards and Technology, cyber-physical systems combine the cyber and physical worlds with technologies that can respond in real time to their environments. Cyber-physical platforms (such as the Internet of Things and the Industrial Internet) include co-engineered interacting networks of physical and computational components; available at https://www.nist.gov/programs-projects/cyber-physical-systems-program.

instituted by the Commission.[21] To achieve this, the Wi-SUN Alliance[22] is providing the forum to develop commercial applications and define testing and certification for interoperable wireless mesh FAN communications[23] for advanced metering and distribution automation. The Companies cited Wi-SUN in the telecommunications RFP, and the industry is working toward Wi-SUN certification and interoperability between devices connected to the FAN.

The Companies' proposed deployment and installation of the FAN-based telecommunications network incorporates flexibility with a logical progression of targeted implementations based on grid needs and customer choice. The GMS referenced both a FAN and a neighborhood area network ("NAN"), but the telecommunications network RFP activity has revealed that the FAN and NAN concepts have converged into a single FAN concept. Accordingly, the Companies' strategic approach for the telecommunications network for the GMS implementation has evolved from what was articulated in the GMS.[24] Details on the refined FAN-based telecommunications network's strategic approach are included in Exhibit G.

Full deployment of the FAN-based telecommunications network to the Companies' entire service territories is not part of the 2019-2023 GMS implementation time frame. Therefore, the Companies will need to determine how the proportional deployment of FAN capabilities fits within the Companies' ongoing planning, procurement, and budgeting processes to support both customer adoption of programs and deployment of field devices. Deployment of the proposed telecommunications network during the Phase 1 portion of the GMS implementation will take into account applicable scenarios provided in Exhibit G.

The combination of advanced meters, an MDMS, and a telecommunications network provides the platform required to begin progressing toward the modern grid necessary to support current and future customer needs and the State's RPS goals. Subsequent GMS phases with their associated applications will build on Phase 1's deployment, utilizing the components installed to enhance future program needs. Indeed, the full potential of these three components cannot be realized without the deployment of other platform system components, such as the ADMS and the associated field devices.

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[21] See Docket No. 2016-0087, Order No. 34281, issued January 4, 2017, at 37.
[22] See Wi-SUN Alliance, available at https://www.wi-sun.org/.
[23] IEEE 802.15.4g standard for wireless mesh smart metering utility networks (SUN), available at http://ieeexplore.ieee.org/document/6486030/.
[24] The August 29, 2017, GMS filing proposed a two-step evolution of the telecommunications network: (1) an open-standard compatible wireless radiofrequency mesh FAN and NAN with cellular communications; and (2) replacement of the cellular FAN connection by connecting to the Companies' expanding deployment of wide area networks ("WANs") for distribution Supervisory Control and Data Acquisition ("SCADA") at the Companies' substations. However, the convergence of the FAN and the NAN has evolved the telecommunications approach to be less sequential and ubiquitous and instead be proportionally engineered based on several factors, including the topography and telecommunication infrastructure available in the geographic region in need of FAN telecommunications solutions.

III. PHASE 2: ADVANCED DISTRIBUTION MANAGEMENT SYSTEM AND FIELD DEVICES

The goal of Phase 2 of the Companies' GMS implementation is to enable advanced distribution capabilities, with a second application currently targeted to be filed by early 2019. To achieve this functionality, the Phase 2 application will include: (1) an ADMS, which serves as a back office system that can efficiently monitor, visualize, and control distribution grid conditions; (2) field devices, including fault current indicators, grid sensors, secondary var controllers, and intelligent switches, which provide distribution grid sensing, control, and automation capabilities; and (3) systems integration to connect the ADMS with existing Energy Management Systems, the recently approved DRMS, the Companies' current and future Geographic Information System ("GIS"), which tracks the geographic location of components of the distribution grid, and the MDMS.

A. ADVANCED DISTRIBUTION MANAGEMENT SYSTEM

An ADMS is a distribution management system with additional modules or functionality enabled, including Volt Var Optimization ("VVO") and an Outage Management System ("OMS"), which includes fault location isolation and service restoration ("FLISR") functionality. Once operational, the ADMS becomes the platform for monitoring and controlling the field devices. The ADMS provides grid operators with near-real-time visibility and control of the distribution system. As the field devices report back data regarding distribution system conditions, the ADMS processes that data to assist grid operators via distribution state estimation, alerts to abnormal conditions, contingency analysis, and recommended switching schemes for load balancing or outage impact minimization. Phase 2's systems integration of the MDMS with the ADMS will enable the sensing capabilities of the advanced meters to notify the Companies when customers are experiencing an outage or abnormal voltage conditions. Integrating these systems will result in faster outage identification and restoration of customer service and improved power quality.

For example, advanced meters as well as field sensors can identify an outage in a certain part of the distribution grid. However, in order to properly assess the outage and develop a restoration plan, the ADMS must receive and process data from multiple systems. The ADMS utilizes the GIS data and has a grid connectivity model to understand the current configuration of the grid as well as all other possible configurations of the grid. The OMS FLISR module of the ADMS can analyze available data to identify the potential root cause(s) of the outage, which can include identification of both the outage location and potentially the infrastructure components causing the outage, and then recommends switching configurations to minimize the number of customers impacted by the outage. This power-characteristic data flow information enables improved situational awareness for distribution operators while also providing grid planners more data and confidence to integrate more distributed generation.

Similarly, both advanced meters and grid sensors can identify voltage issues on a distribution feeder. In this instance, the VVO module of an ADMS coordinates distribution controls to adjust voltage on that feeder. Secondary var controllers and customer-owned advanced inverters can also detect voltage issues and autonomously make adjustments with the

settings managed by grid operators, while load tap changers and phase rebalancing schemes can be enabled by the ADMS.

The Companies are initiating use-case and architecture development activities in the second quarter of 2018 in order to identify the ADMS and field device needs and requirements for each operating utility. The deployment plan will prioritize the implementation of specific functionalities of the ADMS based on the specific needs on each island. The Companies anticipate issuing an RFP for the ADMS in the second half of 2018 using the requirements derived from the use-cases and the architecture. The Companies estimate that an ADMS can be operational within 24 months of the Commission's approval of the Phase 2 application. However, this estimate will be adjusted or validated based on the ADMS proposals received during procurement.

The described ADMS functionality is enabled through the collection of data from other devices and systems, including any and all field measurements; generation, load, and weather forecasts and historical information; accurate physical infrastructure information; and workforce management details. These systems and information flows will need to be integrated using both hardware and some combination of internal and external labor. The data flows, the system needs proportionate with desired functionality, and the scope of integration will be more fully designed in the coming months as the Companies delve deeper into the RFP process for the ADMS.

B. FIELD DEVICES

Another major component of the Companies' future Phase 2 implementation of the GMS includes proportional field device deployment and installation to gradually build their capabilities through a logical progression of targeted implementations based on the areas with the highest prioritized need. The proposed FAN-based telecommunications network deployment as part of Phase 1 is based on a preliminary assessment of areas where voltage or hosting capacity issues could be mitigated through deployment of field devices. However, the Companies' deployment plan needs to be flexible in order to reflect continuing assessment of changing grid needs.

Although the current anticipated implementation of field devices for the grid modernization effort is slated to begin in 2020, the Companies are already deploying field devices through current budgeting processes to begin to address current needs for grid sensing and voltage control. However, the larger scale deployment associated with Phase 2 of GMS implementation will not begin until Commission approval of the proposed Phase 2 application. Subsequently, the Companies will further refine the forecasted number of devices through additional system evaluation prior to submitting the Phase 2 application.

C. SYSTEMS INTEGRATION

Grid modernization requires integrated systems that exchange information to manage the grid. Figure 2 presents a high-level architectural view of the anticipated GMS Phase 1 platform integration that will be necessary including interfacing with existing systems like CIS and DRMS. Capabilities will increase over time, with additional integration between the ADMS, the

DRMS, and the MDMS contemplated in Phase 2 to leverage advanced meter data as grid-sensing input for distribution management, outage management, VVO, and system data analytics.

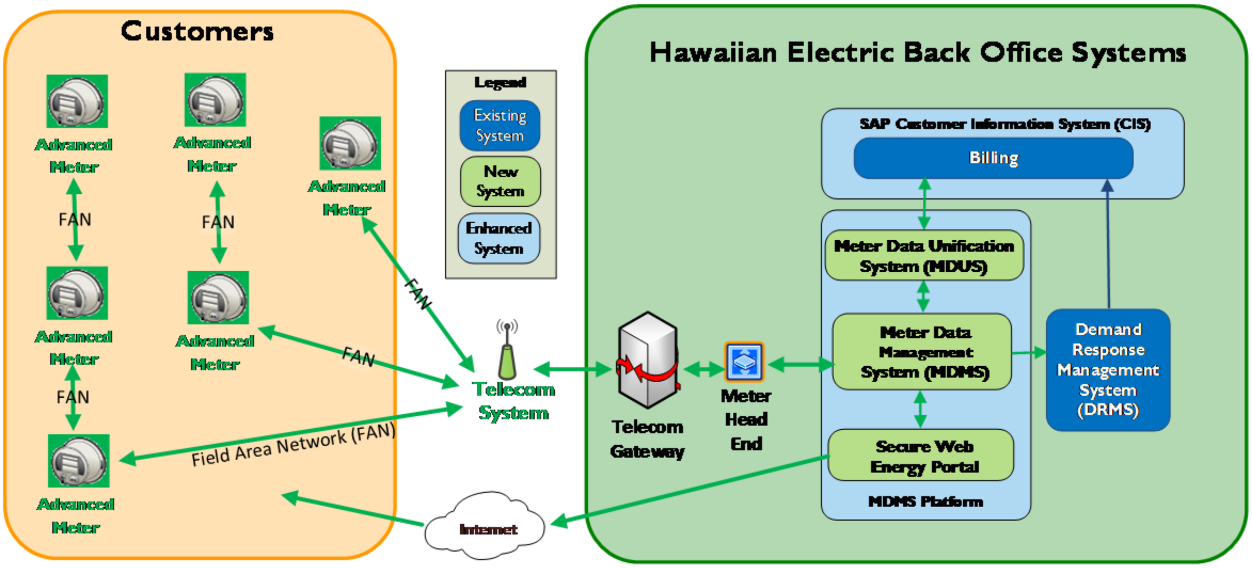

Figure 2

IV. FUTURE PHASES FOR GMS IMPLEMENTATION

Although the Companies are proceeding with the implementation of the GMS, some components still require additional evaluation to determine the necessary scope to fulfill customer needs as well as the expectations of all stakeholders. One component being explored includes operational analytics tools to assist in digesting all of the information from the modernized grid. Analytics capabilities are evolving to both assist in more efficient grid operations and to provide insight for future planning and forecasting. The MDMS and ADMS solutions inherently provide some analytics capabilities; however, there may be gaps between the Companies' analytics needs and the capabilities provided by these products. Therefore, a gap analysis will be performed to determine what, if any, additional analytics capabilities are required to progress forward with future phases of the GMS.

Additionally, the Companies will need to explore the capabilities of the existing and planned infrastructure needed for a NOC to support network monitoring of the telecommunications solution as it expands over time. Similarly, a distribution operations center ("DOC") for the ADMS may be needed to allow system operators to manage the distribution system; it is assumed that the requirements of the DOC will be incorporated into the existing operations dispatch center. However, additional infrastructure requirements will need to be further vetted upon completion of Phase 2 of the GMS implementation.

Exhibit B

GMS Phase 1 Application

Project Justification with Business Case Support

Note: References to exhibits in this document refer to exhibits included in the accompanying application unless otherwise noted.

PROJECT JUSTIFICATION WITH BUSINESS CASE SUPPORT

This project ("Phase 1") is the first phase in implementing the recently approved Grid Modernization Strategy ("GMS")[1] and will play an integral role in assisting the Hawaiian Electric Companies[2] to advance modernization of the grid[3] and achieve their 100% Renewable Portfolio Standards ("RPS") goal by 2045.[4] In particular, Phase 1 seeks approval to commit $86.3 million in capital and deferred funds for the following scope of work:

1) Proportional deployment of advanced meters to enable recently approved Distributed Energy Resources ("DER") programs (Customer Grid Supply Plus ("CGS+") and Smart Export)[5] and Demand Response ("DR") Portfolio.[6] The advanced metering solution will support and enable existing and future customer energy options;[7]

2) A Meter Data Management System ("MDMS") to store and manage the data collected from the advanced meters; and

3) A telecommunications network, including a Field Area Network ("FAN"), to communicate with both advanced meters and field devices to enable distribution grid monitoring, control, and automation in coordination with the Companies' grid operations.

Collectively, these initial GMS components begin to build a modern grid platform that advances the grid toward the Hawai'i Public Utilities Commission's ("Commission") vision for a robust customer energy options market, and paves the way for future programs that will further enhance customer value, provide more functionality, and streamline workflow processes and facilitate efficiencies.

The proposed GMS implementation is consistent with past Commission guidance in related dockets and supports operationalization of the current and future programs. Without GMS investments, customer choice will be limited and already-approved customer energy options and their respective benefits will not be fully realized. The alternative to the grid modernization is a classic "wires" approach to building a more robust grid by reconductoring

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[1] See Docket No. 2017-0226, *Modernizing Hawai'i's Grid For Our Customers*, filed August 29, 2017.
[2] The "Hawaiian Electric Companies" or "Companies" are Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Maui Electric Company, Limited ("Maui Electric") and Hawai'i Electric Light Company, Inc. ("Hawai'i Electric Light").
[3] See, e.g., Hawai'i Revised Statutes § 269-145.5(b).
[4] See Hawai'i Revised Statutes § 269–92.
[5] See Docket No. 2014-0192, Decision and Order No. ("D&O") 34924, issued October 20, 2017.
[6] See Docket No. 2015-0412, D&O 35238, issued January 25, 2018.
[7] The term "customer energy options" as utilized in this Application is inclusive of existing and new tariffs and/or programs including DR Portfolios (including TOU and future dynamic pricing) and DER programs. All of these options would be inclusive of any customer-sited resources, including but not limited to photovoltaic ("PV"), distributed storage, and electric vehicle ("EV").

lines, or adding other traditional power grid investments to increase hosting capacity, but these investments are less dynamic and less efficient. The GMS was identified as a more cost-effective approach than the "wires" alternative contemplated in Companies' Power Supply Improvement Plan ("PSIP").[8]

The Companies are proposing to deploy Phase 1 in an as-needed, where-needed manner that will maximize value for customers while minimizing rate impacts. Specifically, this targeted approach is intended to enable and assist in realizing the benefits of customer energy options. For example, over time, as more field devices and deployed advanced meters reach greater levels across each utility, operational savings will be realized to the customers' benefit.

Furthermore, the deployment will provide:

- Improved metering functionality and efficiency that will support customer energy options.
- Advanced metering sensing and control capability with that will provide valuable operational data and control; grid operators and distribution planners will better identify, manage, and potentially take mitigating action for voltage and frequency issues that will be fully enabled through the second phase ("Phase 2") of the GMS Advanced Distribution Management System ("ADMS").
- A customer energy portal to provide customers with insight to better manage their energy usage.
- Deployment of a telecommunication solution to support both advanced metering and field devices that will be further deployed in GMS Phase 2.

This proportional and phased approach not only prioritizes when and where GMS investments should be made, but also mitigates risk by adopting the latest technologies and taking advantage of new advancements over time. As more field devices and advanced meters are deployed, reliability and operational improvements will be realized to the customers' benefit. In short, without these Phase 1 investments, customer energy options will be limited and their respective benefits will not be fully realized.

As discussed below, Phase 1 is expected to be cost-beneficial under a lowest reasonable cost analysis and when considered in the context of enabling distributed customer energy options that can provide more cost-effective alternatives to traditional wired investments.

I. BACKGROUND

As discussed in the GMS, modernizing the electric grid is an infrastructure investment that provides a platform for current and future program-specific benefits that will enable

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[8] See Docket No. 2014-0183, *PSIP Update Report: December 2016*, filed December 23, 2016; see also GMS, Section 8.4 (Alternatives).

customer value and help the Companies achieve the State's RPS goals.[9] This will be done through a phased approach, as described in Exhibit A (*Working Plan*), and will require an estimated total investment of approximately $205 million, spread over multiple phases of the GMS.[10] Phase 1, which encompasses the accompanying application ("Application"), proposes to implement the necessary technologies identified in the GMS that enable customer choice and address existing requirements stemming from recent Commission rulings, at the lowest reasonable cost to customers.

Specifically, Phase 1 will enable current and future customer-facing programs that facilitate customer choice through expanded adoption of customer energy options and integration of community-based renewable energy ("CBRE")[11]. Each new customer energy option utilizing new technologies (e.g., energy storage) has unique benefits that are (and will be) the basis for Commission consideration of each individual program.

The Capital and Deferred Costs associated with Phase 1 are estimated at $86.3 million (or 42% of the total estimated GMS budget presented in the Companies' August 29, 2017 filing), and include investments in three main components that align with the preliminary platform configuration of the Companies' planned modernized grid: (1) advanced meters; (2) an MDMS; and (3) a FAN-based telecommunications network. When viewed in isolation, the individual components do not present direct, quantifiable operational benefits; rather they should be viewed in the context of existing policies regarding customer choice and environmental goals. Additionally, these initial components establish the necessary interrelationship to a more complete platform that will be introduced in subsequent GMS phases that will yield operational benefits from the combined investments. Phase 1 of the GMS will provide the advanced metering solution for the recently approved Smart Export and CGS+ programs and DR Portfolio. However, the Companies recommend that the Commission take advanced metering costs into account when considering the benefits and costs for future customer energy options.

Meeting customers' needs and achieving Hawai'i's clean energy goals is not possible with the current grid; the grid the Companies currently have is not the grid they need. Phase 1 of the GMS implementation will provide investment and capabilities to evolve the grid and enable the integration and optimal utilization of customer resources made available through existing and new DER programs and DR Portfolio, as reflected by the renewable generation level projections in the Companies' *PSIP Update Report: December 2016* and summarized in Table 1

, below. Importantly, the Companies' PSIP assumes that DER programs and DR Portfolio are needed to meet a significant portion of the State's RPS goals. Accordingly, the necessary technologies presented in Phase 1 are key enablers both to these programs and the attainment of the related PSIP projections.

[9] See GMS, Section 4.2 (Cost-Effectiveness Framework).
[10] See id., Section 8.3 (Conceptual Cost Estimate for Near-Term Roadmap).
[11] See Docket No. 2015-0389, "D&O 35137, issued December 22, 2017. The CBRE program may utilize the GMS implementation infrastructure to enable benefits for smaller projects.

December 2016 PSIP Projections for DR and DER		
Generation Source	2017-2021	2022-2045
New Distributed Solar Photovoltaic (DG-PV)	326 MW	2,086 MW
New Customer Self-Supply (CSS) Energy Storage	89 MWh	1,057 MWh
New Demand Response Capacity	115 MW	442 MW
New Demand Response Energy Storage	104 MWh	1,608 MWh

Table 1

The Companies' vision is to use advanced technologies to modernize the existing grid into a platform for enhancing customer value, provide operational flexibility to integrate more renewables, reduce Hawai'i's dependence on imported oil, and spur economic development. New grid technologies introduced as part of Phase 1 (as well as future phases of the GMS implementation) will support increased adoption of private rooftop solar, make use of rapidly evolving products (e.g., energy storage and advanced inverters) and incorporate a vast array of sophisticated energy management tools, such as those instituted through the Companies' DR program(s).[12] Phase 1's platform will further enable variable pricing, such as TOU,[13] DER compensation programs such as Smart Export, and DR Portfolio execution. Grid modernization investments will also support utilization of stored energy to help meet peak demand and then recharging when solar generation is abundant. From an operational perspective, the technologies and systems proposed through the progression of GMS phases, beginning with the components presented as part of Phase 1, will enable system operators to engage with DER and DR resources to maintain grid stability.

The Commission has emphasized the importance of grid modernization to: (1) enable greater penetration of renewable generation and customer energy options; (2) expand energy options for customers to manage their energy usage; and (3) automate system control and operation of the electric grid. Phase 1 is consistent with the GMS and addresses these key concepts raised by the Commission. Additionally, Phase 1 employs a proportional and incremental implementation prioritized to support both grid and customer needs to minimize rate impacts and maximize customer value.

II. BUSINESS CONTEXT

The Commission has provided guidance to assist the development, planning, and execution of the Companies' GMS. The planned implementation of the GMS is aligned with key points raised in a number of dockets and Commission decisions:

- The *Commission's Inclinations on the Future of Hawaii's Electric Utilities*[14] offered many points that provided a foundation and need for the grid modernization scope in the accompanying Application (paraphrased for brevity):

[12] DR compensation to both customers and aggregators is performance-based. Advanced metering and the MDMS are needed in order to collect the meter data to support DR program measurement and verification which determines the DR incentive payments.
[13] TOU rates could be used to encourage charging EVs during times of peak solar output.
[14] See Docket No. 2012-0036, D&O 32052, issued April 28, 2014, Exhibit A, at 14.

  - Focus on delivering immediate value and benefits to customers with installation of smart grid infrastructure; and
  - Enable customer-sited DER, including broader use of DR technologies, EV charging networks, distributed generation, and energy storage systems.

- In the DR D&O, the Commission stated that coordination and alignment of the DR Portfolio with interrelated and overlapping proceedings (including grid modernization) are "residential critical to the success of each."[15]

- In a DER D&O,[16] the Commission ordered two new programs (i.e., CGS+ and Smart Export) and the utilization of advanced meters[17] that will use some or all of the functionality required in future DER programs (visibility, controllability, and the ability to enable new tariffs).

- In the GMS D&O,[18] the Commission emphasized the importance of grid modernization to: (1) enable greater penetration of renewable generation and customer-sited DER; (2) expand energy options for customers to manage their energy usage; and (3) automate system control and operation.

Figure 1 below provides a visual representation of the interrelationships between the Companies' GMS and how it will feed into their PSIP, DER, Integrated Grid Planning ("IGP") and DR-related programs. Beginning with Phase 1, the platform developed and deployed as part of the GMS will drive the grid toward achieving more renewable integration (as described in the PSIP), enable more customer energy options, and enable exploration of alternatives to meet the needs and expectations of Hawaiʻi's communities and stakeholders to modernize the electric grid, as proposed in the IGP filing. Collectively, these plans and programs lay out a conceptual framework for the Companies to successfully innovate and achieve necessary enhancements while continuing to pursue technologies that appeal to customers' needs and interests.

[15] See Docket No. 2015-0412, D&O 35238, issued January 25, 2018, at 91.
[16] See Docket No. 2014-0192, D&O 34924, issued October 20, 2017.
[17] The Companies recognize that the Commission ordered the use of "smart meters" and "smart net meters" to fulfill each programmatic requirement, but consistent with the definitions utilized in Exhibit K – *Glossary of Terms*, the Companies are adopting "advanced meters" to fulfill the requirements.
[18] See Docket No. 2017-0226, D&O 35268, issued February 7, 2018.

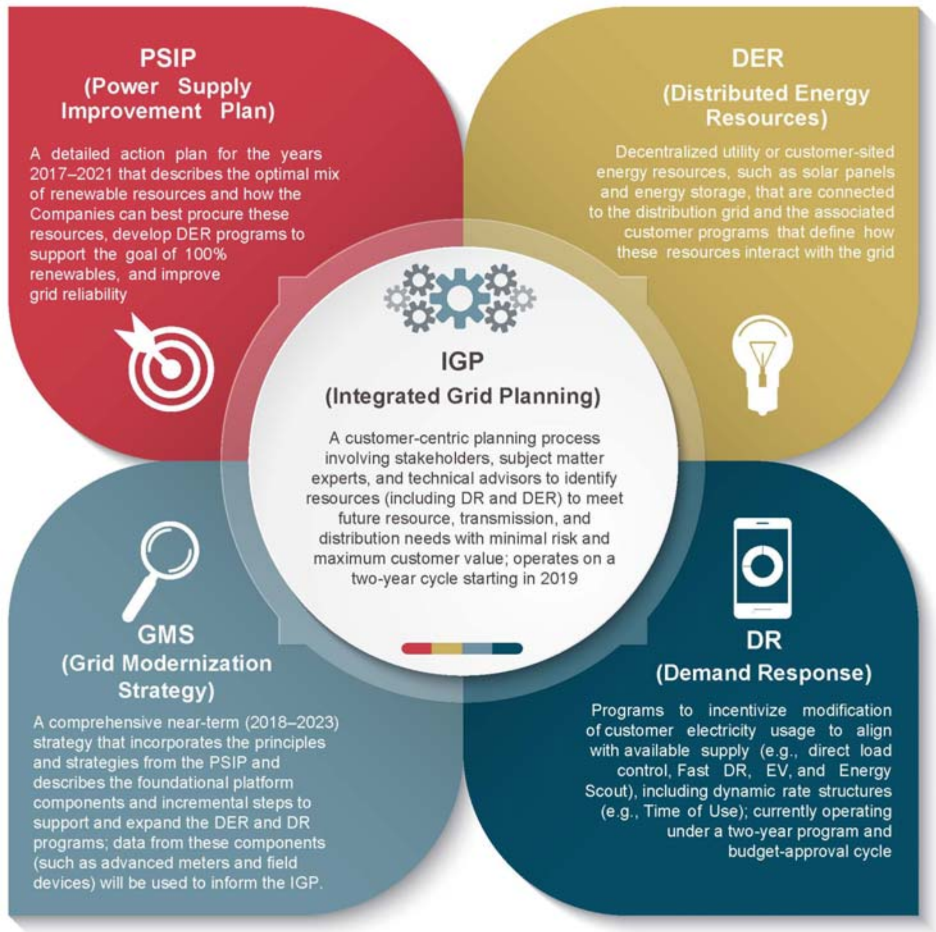

Figure 1

The Phase 1 deployment of advanced meters, an MDMS and a telecommunications network infrastructure aligns with the Commission's guidance. These investments derive customer and stakeholder benefits by enabling the existing CGS+/Smart Export DER programs and DR Portfolio. These investments, in turn, will enable expansion of more distributed customer-sited resources and will also support future customer energy options (including Electrification of Transportation ("EoT") while making progress toward the State's RPS goals.

In addition, advanced meters provide grid sensing information to deliver notifications of outages and voltage issues, capabilities that will be utilized as part of the Phase 2 of the GMS implementation, which will involve deployment of an ADMS to the benefit of all customers. The telecommunications network is a key platform investment that will enable not only advanced meter communications but also field device communication for distribution grid monitoring, control, and automation as a part of future phases of the GMS, inclusive of Phase 2 and beyond.

This proportional and phased approach not only prioritizes when and where GMS investments should be made, but also mitigates risk by spreading deployment costs over time and adopting the latest and most appropriate technologies at the lowest reasonable costs. Concurrently, the phased deployment strategy further addresses specific customer and grid needs while increasing the Companies' capabilities to monitor and manage the distribution grid. Dividing the implementation of the GMS into multiple phases also reduces the implementation risk for the Companies by segmenting the deployment into manageable and sequential projects that build technical capabilities over time.

The phasing and prioritization of the GMS implementation is a near-term effort to address known priorities for systems and technology investments that also aligns with Commission guidance and enables progression toward the State's RPS goals. Going forward, the Companies expect that the recently filed IGP process will inform the use of distributed and grid-scale renewable resources and the related need for distribution modernization, transmission projects, and energy storage.[19] This in turn will inform the Companies' general rate cases and any related regulatory proceedings (e.g., DER, DR, and EoT).

In the time since the Commission issued its *Inclinations* and accepted the Companies' PSIP, development of programs consistent with the PSIP have continued to move forward without the implementation of grid modernization. In the recent DER order,[20] the Commission ordered two new programs (i.e., CGS+ and Smart Export) that will utilize some or all of the functionality likely needed for other future DER programs as well. Specifically, advanced meters with communications will provide visibility, controllability, and the ability to provide different credit rates for different time periods of export. However, prior to Commission approval of Phase 1, the required functionality for these new programs will be accomplished with an interim metering solution. Because the equipment that will be used for the interim solution is neither consistent nor compatible with the GMS approach for the FAN-based telecommunications network, it will be deployed as minimally as possible to curb the risk of stranded investments while still implementing the programs. The Companies expect that either the interim metering solution units will subsequently be replaced by the advanced meters, pending Commission approval of this Phase 1 Application, or an adapter will be utilized so that the interim metering solution data can be loaded into the MDMS on a continuing basis.

In the DR docket, the Companies reiterated that "the DR Portfolio will benefit from, if not rely on, key elements outlined in the GMS. In fact, the GMS effort to date has taken into account the DR Portfolio, "with a full and clear understanding of the implications of the technology roadmap to ensure synergistic alignment."[21] As a result, the Companies' GMS implementation is expected to enable the DR approach described in the Companies' applications.

More recently, the Companies filed their *Electrification of Transportation Strategic Roadmap*,[22] which represents a promising opportunity to further leverage GMS investments and

[19] See the Companies' *Integrated Grid Planning Report* filed March 1, 2018, available at http://hawaiianelectric.com/igp.
[20] See Docket No. 2014-0192, D&O 34924, issued October 20, 2017, at 10.
[21] See Docket No. 2015-0412, D&O 35238, issued January 25, 2018, at 99.
[22] See Docket No. 2016-0168, *Electrification of Transportation Strategic Roadmap*, filed March 29, 2018.

derive additional value for customers. This is enabled through the GMS investment in both advanced metering to enable EV tariff designs and execution as well as the customer energy portal as a part of the MDMS investment. These capabilities enable greater customer engagement and empowerment, as well as options for utilizing and providing energy services.

Not only do the components of the Companies' modernized grid allow for the execution of advanced tariffs, the components themselves will inform program refinement and more optimal utilization of resources on the grid. For example, advanced meter data will support development of accurate forecasts of EV load profiles and load growth, help the Companies understand how to appropriately incentivize daytime charging during peak generation, and facilitate integrated planning with renewable generation and distribution planning. This will create value for both EoT and non-EoT customers by enabling improved customer engagement, supporting more efficient and reliable distribution planning, enabling the design and targeting of smart charging programs, and incentivizing EV adoption to utilize excess renewable generation. The vision for a fully flexible grid also benefits third-party technology providers and aggregators by allowing them to convey pricing signals to car owners, providing them an opportunity to demonstrate a variety of new and innovative solutions and business models.

III. <u>SCHEDULE/OPERATIONAL IMPACTS</u>

The components of Phase 1 are expected to commence deployment and implementation upon approval by the Commission, which the Companies are anticipating to take place approximately 12 months following the submission of the accompanying Application, as shown in Figure **2** below. Phase 1 has been budgeted for 2019-2023; however, since the proportional and phased deployment strategy of the GMS is dependent upon customer enrollment in customer energy options, the costing for deploying the advanced metering and supporting telecommunication solution is highly variable.

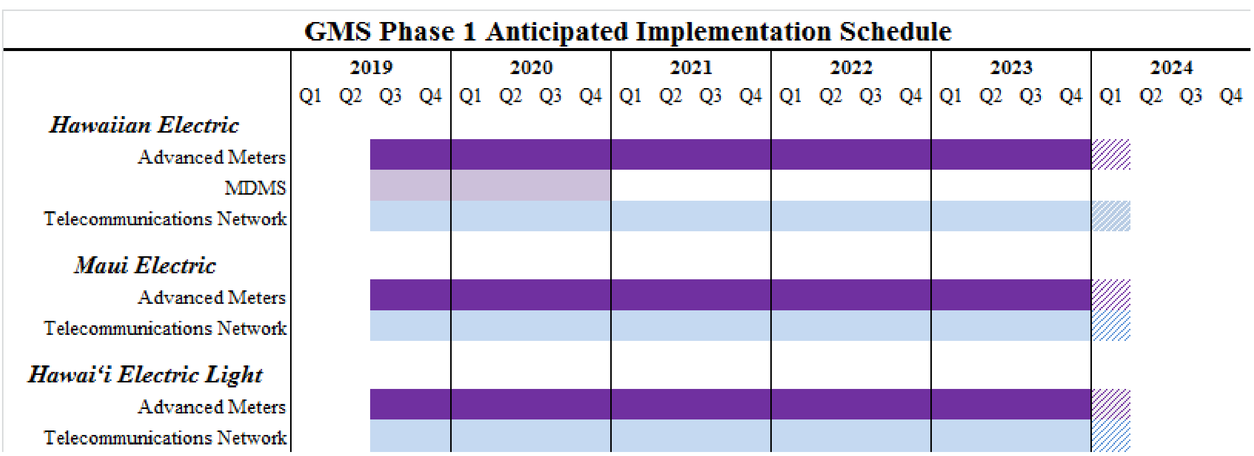

Figure 2

Advanced meters will be deployed incrementally beginning in 2019 and ending in 2023 (or early 2024 depending on when Commission approval is received) to initially support customer participation in Smart Export, CGS+, the DR Portfolio, new customer energy options, as well as new meter sets and meter replacements. The advanced meters will be deployed using a combination of internal labor and outside contractors.

The MDMS will take approximately 15 (total, concurrent) months to implement, including the establishment of interfaces with the telecommunications gateway, advanced meters' headend, the Commission-approved Demand Response Management System ("DRMS"),[23] and the Companies' SAP Customer Information System ("CIS")[24]. The CIS to MDMS interface is a standardized meter data unification and synchronization ("MDUS")[25], which was developed by SAP and MDMS vendors. The interface will simplify system integration and reduce implementation risks, and will use a combination of internal labor and labor provided by the selected MDMS vendor.[26]

The proportional deployment of the proposed telecommunications network component of Phase 1 is anticipated to span the entire 2019-2023 timeframe, and will include a combination of resources including internal field services and telecommunications engineering resources, as well as external contractors. Further details on the telecommunications network's deployment approach are included in Exhibit G (*Telecommunications Network Considerations*).

IV. EXPECTED INVESTMENT

A. PROJECT COST ESTIMATE

The conceptual estimate included in the GMS was $205 million.[27] The combined Capital and Deferred Cost for Phase 1 of the GMS over its anticipated 2019-2023 implementation is estimated at $86.3 million. This cost estimate aligns with estimates for the respective technologies identified in the GMS and discussed in Exhibit A. The implementation costs associated with the three main components of Phase 1, broken down by utility and accounting treatment, are provided in Table 2 below.

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[23] See Docket No. 2015-0411, D&O 34884, issued October 18, 2017. As indicated in Docket No. 2015-0411, the Companies are planning for the DRMS to evolve to a full Distributed Energy Resource Management System to facilitate the utilization of the Companies' DR programs and aggregated DER from others to manage the power system. Applicable capabilities will be utilized upon completion of implementation and evaluated in Phase 2 of the GMS implementation.
[24] See SAP for Utilities Billing and Revenue Management, available at https://www.sap.com/industries/energy-utilities/billing-revenue-management.html.
[25] See SAP Documentation, *Advanced Metering Infrastructure*, available at https://help.sap.com/erp2005_ehp_05/helpdata/en/eb/75df7f40b741869203c56b5563b415/frameset.htm
[26] The Companies anticipate making a final vendor selection for their MDMS in late 2018, and will refine their labor costs associated with the selected vendor to revise their total anticipated outside service costs provided later in this Exhibit.
[27] See GMS, at 110 (Section 8.3), *Table 9: Conceptual Capital and Software Cost Estimate for Near-Term Investments*.

GMS Phase 1 Total Implementation Costs By Utility and Component ($000s)					
		Advanced Meters + Headend	Meter Data Management System (MDMS)	Telecommunications Network (FAN+NAN) + Headend	**Total**
Hawaiian Electric	Capital	[redacted]			
	Deferred				
	Total				
Maui Electric	Capital				
	Deferred				
	Total				
Hawai‘i Electric Light	Capital				
	Deferred				
	Total				
Consolidated Total		[redacted]	[redacted]	[redacted]	**$86,257**

Table 2

The advanced meter component of Phase 1 totals approximately [redacted]. The Companies plan to primarily utilize internal resources supplemented with external contractors for the installation of these devices for customers who enroll in customer energy options that require the use of advanced metering technologies. Unlike what was proposed in the prior Smart Grid Foundation Project ("SGFP") application, the Companies will not be deploying advanced meters to all customers as part of the GMS implementation. Rather, concurrent with and following the initial deployment for customer participation in customer energy options, the Companies plan to gradually phase-in the use of advanced meters as the Companies' new meter standard for new customer service requests and replacements in the future. Also, it is anticipated that at some point in the next decade, the operational benefits of deploying advanced meters to the remaining non-advanced meter customers will outweigh the cost to complete deployment. Table 3 below shows the forecasted meter deployment, which is based on capacity limits of the current programs and historical deployment of new or replacement meters.

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

Table 3

The MDMS component's total investment for Phase 1 is estimated at [redacted]. This cost includes internal and external labor and vendor-supplied software and materials. The proposed MDMS will be the system of record for the advanced meters' data and configuration,

and will be interoperable with other systems, including the CIS for billing and DRMS for the DR Portfolio measurement and verification. The MDMS will provide data for an integrated online customer energy portal to provide customers and customer-authorized third parties access to energy usage data. The functional efficiency and usefulness of the MDMS will improve energy management, data collection and assimilation, and grid control. The deployed advanced meters will communicate with the MDMS through the proposed telecommunications network. The MDMS will also provide data for analytics to refine load profiles and additional data for distribution planning in pursuit of customer needs and State policies.

The telecommunications network proposed for Phase 1 is budgeted at approximately [redacted] Similar to the MDMS, the planned telecommunications network will include both internal and external labor and resources, including vendor-supplied software and devices. The FAN-based telecommunications network will not only support the advanced meters but will also provide connectivity to field devices that provide distribution grid sensing, control, and automation, which will be included as part of the future Phase 2 deployment of the GMS. The proposed telecommunications network will expand to enable the connection of additional advanced meters and field devices over time, and will be scalable to increase bandwidth and decrease latency as needed to support future growth. Expanding the telecommunications network over time will allow for future expansion and integration with the Companies' numerous current and future customer energy options, which will contribute toward the Commission's long-term vision of a robust customer energy options market throughout the Companies' service territories.

For enterprise systems, including the MDMS and meter headend systems, the effort to implement these projects will occur at Hawaiian Electric. Since the systems will benefit all customers, the Companies will allocate the costs among the three utilities through their traditional breakdown pricing structure of 70/15/15, where 70% of the total consolidated costs will be borne by Hawaiian Electric, 15% by Maui Electric, and 15% by Hawaiʻi Electric Light.

Table 4 below presents a similar cost presentation to that shown in Table 3 above, broken out by utility and year of implementation.

GMS Phase 1 Total Implementation Costs by Utility and Year ($000s)							
		2019	2020	2021	2022	2023	Total
Hawaiian Electric	Advanced Meters + Headend	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MDMS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Telecom Network + Headend	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Maui Electric	Advanced Meters + Headend	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MDMS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Telecom Network + Headend	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawai‘i Electric Light	Advanced Meters + Headend	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MDMS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Telecom Network + Headend	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Consolidated Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**$86,257**

Table 4

The costs for each of the three main components of Phase 1 are generally broken down into the following six cost categories: (1) internal labor; (2) materials; (3) outside services; (4) other; (5) overheads; and (6) allowance for funds used during construction ("AFUDC"). The consolidated costs by year (including details explaining each cost category) that the Companies expect to incur under each of these categories are shown in Table 5 below.

GMS Phase 1 Total Implementation Costs by Component and Year ($000s)							
		2019	2020	2021	2022	2023	**Total**
Advanced Meters + Headend	Internal Labor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Materials	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Outside Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Overheads	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	AFUDC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MDMS	Internal Labor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Materials	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Outside Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Overheads	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	AFUDC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Telecomm Network + Headend	Internal Labor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Materials	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Outside Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Overheads	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	AFUDC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Consolidated Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**$86,257**

Table 5

The internal labor cost category, which totals approximately [redacted], includes costs for the internal employee effort on all three components of the project's deployment. Among other things, internal employees are needed to work on the project so that new processes and capabilities will be maintained and retained within the Companies over the long term. Details of internal labor costs by utility are provided in Exhibit H (*GMS Phase 1 Project Costs*).

The materials cost category, which totals approximately [redacted], includes costs described in Exhibit C (*Accounting and Ratemaking Treatment*).

The outside services cost category, which totals approximately [redacted], includes costs for external vendor staff services for all three components. These costs consist of both

consultants and request for proposal ("RFP") awardees that have provided anticipated estimates on labor needs as part of the Phase 1 deployment and implementation period.

The "other" cost category, which totals approximately [redacted], includes the deferred costs for software licensing fees and external information technology labor for software implementation, integration, and testing. Due to coding in the Companies' financial system, the expense elements 461 – Information System Exp – Consultants, and 462 – Information System Exp – Software Purch, are reflected in the "other" cost category.

The overheads cost category, which totals approximately [redacted], was developed using the Companies' budgeting software (UI Planner) and represents an allocation for those Company costs that are not attributed to any particular project or operation, but are essential nonetheless. Overheads are comprised on non-productive wages (such as holiday, sick, and vacation pay), employee benefits, payroll taxes, corporate administrative costs, and clearing costs.

The AFUDC for the Project was obtained using the Companies' budgeting software (UI Planner). The total amount of the estimated AFUDC is [redacted].

All costs include the relevant general excise taxes ("GET") as applicable at either 4.712% or 4.5%, depending on tax guidelines. GET is mainly applied to equipment, hardware, software, outside services, and maintenance licensing costs.

B. OPERATIONS AND MAINTENANCE COSTS

In addition to the Capital and Deferred Costs, the Companies will incur expense and removal costs during the implementation of Phase 1. Post go-live, there will also be incremental, on-going operational costs for staff and hardware/software maintenance for the proposed projects. These resource needs and on-going costs will be assessed once the respective vendors are selected. None of these costs are included as part of the accompanying Application as their recovery will be through base rates. To the extent that these costs are not recovered in current rates, the Companies plan to address recovery of these costs in future rate cases.

V. PROJECT RISK MANAGEMENT

The Companies have identified several key project risk areas based on over a decade of industry experience implementing metering, communications and related data management systems as described above: 1) technology selection; 2) vendor experience; 3) system integration; and 4) project complexity. These risks are being proactively managed through the Companies' procurement process and multi-phase application structure.

The technology selection process began with the development of a grid architecture based on the U.S. Department of Energy's Grid Architecture framework, as discussed in the GMS. This architecture was followed by developing functional requirements informed by customer needs, Commission guidance, and rulings, as well as business needs. The use-case method, drawing on the Electric Power Research Institute's ("EPRI") extensive library of existing utility use-cases, was used to identify these process and technology requirements. These requirements have the benefit of having been vetted by EPRI and in industry actual practice.

The architecture and requirements development process is important to inform technology selection through the subsequent procurement. This approach significantly reduces the risk of missing important details that otherwise may arise after selection and during implementation. Vendor selection is also an important part of the technology procurement process. Customers will benefit from a robust set of metering, meter data management software, and communications products. The technology products under current evaluation represent the collective industry learnings and continued refinements over the past decade and over 60 million smart meters and related advanced metering infrastructure communications deployed across the United States. The vendors under consideration have significant organizational experience and capability to support the proposed implementation.

The Companies are in the process of administering formal RFPs for advanced meters, the MDMS, and the telecommunications network. As of the filing of the accompanying Application, the Companies have received proposals from vendors, and have down-selected vendors for each component, but have not formally selected the final vendor for any individual component of Phase 1. Although the RFPs have not been awarded, the proposals received from vendors have been used to inform the cost estimates for Phase 1.

System integration is recognized as a major risk area on grid modernization projects because of the large number of interfaces combined with data latency and quality considerations. In taking a multi-phased approach to grid modernization, the Companies have reduced the number of interfaces and the level of complexity in Phase 1 significantly. Also, the primary interface with the billing system is streamlined through the use of the MDUS application that was designed ten years ago to simplify the MDMS to CIS integration. The Companies will select a combination of meters, MDMS, and communications from vendors with products with proven interfaces and integrations and potentially enable less-complex integration with the ADMS and any other systems proposed in subsequent phases.

The multi-phased approach and proportional deployment of the Companies' GMS reduces the overall complexity of implementation, as highlighted above. However, there continues to be a need to employ a strong project management approach with effective scope, schedule, and budget controls. The Companies have established a dedicated project management team and governance and engaged internal subject matter experts from relevant organizations and experienced consultants. The Companies are confident that this approach to grid modernization will result in a successful deployment and long-term value for customers.

VI. BENEFITS OF A GRID MODERNIZATION PLATFORM

Legislative and regulatory direction have encouraged customer choice in Hawai‘i, including utility and aggregator customer energy options with electric system benefits identified by the Commission, as well as enabled progression toward RPS goals. The realization of these benefits depends on the development of a modern grid platform to enable Hawai‘i's energy future. The Companies are in agreement with the Commission regarding the need to develop "a grid platform that increases opportunities for distributed technologies, optimizes grid assets to

minimize costs, enables customer participation in consumption and energy services, and enhances grid safety, security, reliability, and resilience."[28]

Additionally, the Companies recognize the need to consider the impact of grid modernization investments on rates and customer affordability. As such, the Companies are proposing to implement grid modernization in an as-needed, where-needed manner that will maximize value for customers while minimizing rate impacts. Specifically, this targeted approach is based on realizing the benefits of customer energy options. Over time, as more field devices and deployed advanced meters reach greater levels across each utility, operational savings will be realized to the customers' benefit. For example, until advanced meter deployments reach a saturation point for an area, meter readers will still be needed to physically read those meters that have not yet been replaced. In this example, a question often raised is, "Why not replace all meters now?" The answer is that the operational savings of full, immediate replacement are insufficient to make a positive case for customers.[29] Therefore, the Companies' implementation of the GMS addresses the Commission's findings and direction in the SGFP decision and several other DER-related decisions to enable current and future customer energy options.

The various investments presented in this Exhibit as part of Phase 1 enable customer energy options. Through the advanced meters and telecommunications network, these investments will also provide initial grid sensing capabilities, which will begin to enable cost-effective alternatives to the estimated wires upgrades proposed in the Companies' PSIP to enable customer adoption of DER.[30] The customer benefit of implementing the GMS versus implementing solutions identified in the PSIP is reflected in the difference in the conceptual cost estimates for the two alternatives depicted in Figure 3 below. This figure adapts the conceptual wires estimate in the PSIP to that of the conceptual GMS estimate, which includes a small amount of selective physical upgrades, to create an "apples to apples" comparison. Based on this comparison, this GMS implementation is more cost-effective than the wires alternative by $121 million in the near term and more in the longer term between 2018 and 2023. This reduction in total cost improves the overall cost-benefit of DER for all customers.

[28] See Docket No. 2017-0226, D&O 35268, issued February 7, 2018, at 26.
[29] See Docket No. 2016-0087, D&O 34281, issued January 4, 2017.
[30] See GMS, Section 8.4 (Alternatives).

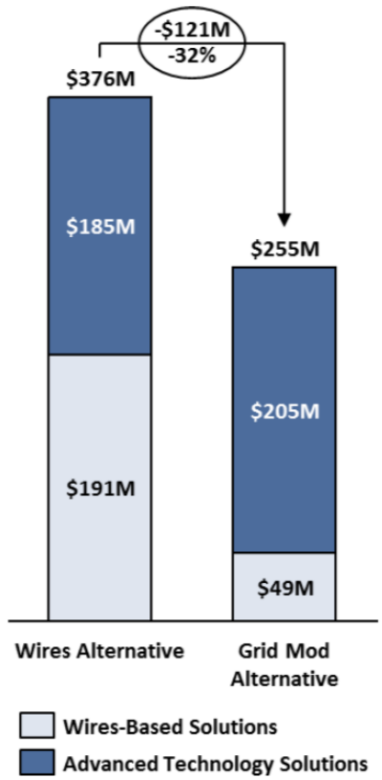

Figure 3: GMS Solution v. PSIP Solution

In short, without these investments, customer energy options will be limited and their respective benefits will not be fully realized.

Figure 4 below illustrates the interrelationship of several components described in Phase 1 and the creation of the platform envisioned to support these uses and others into the future.

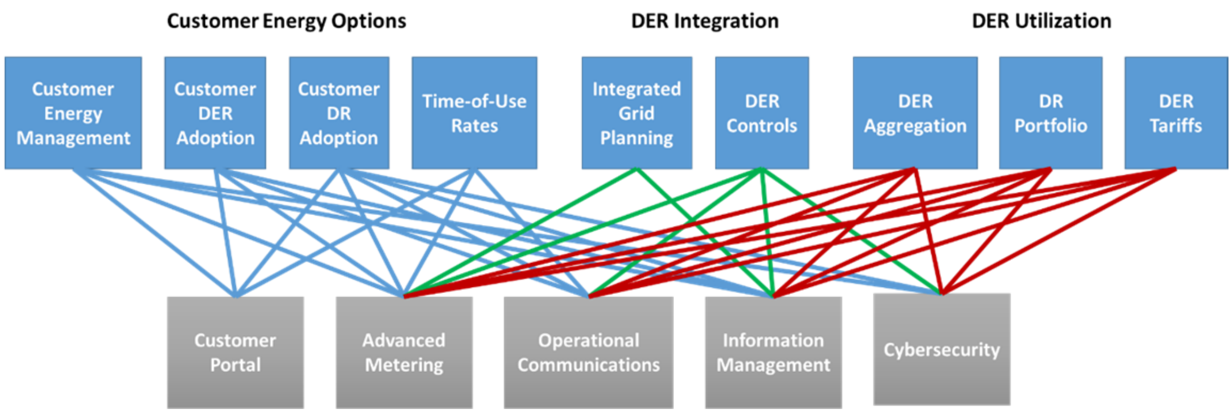

Figure 4

In the 2019-2023 implementation timeframe for Phase 1, the proposed incremental and proportional deployment will allow the Companies to continue to grow the programs and services that are made available for customers while ensuring that these advanced technologies are gradually introduced to minimize cost impacts and reduce the risks of both stranded costs and project implementation delays.

As discussed herein, Phase 1 is expected to be cost-beneficial under a lowest reasonable cost analysis and when considered in the context of enabling customer energy options, as well as in providing cost-effective alternatives to traditional wires investments. Therefore, it is prudent and necessary for the components presented in Phase 1 to be implemented into the Companies' electric grid in order to achieve the benefits identified in the various DR and DER decisions, in addition to contributing to the Companies' ability to achieve the State's RPS and EoT goals. The Companies' plan for a modernized grid to be implemented in phases and that incurs costs spread over the duration of implementation will result in a more affordable grid modernization deployment for customers.

A. INTERIM TOU-RI PILOT

Despite the monthly bill impact for GMS investment at each of the Companies, the cost will be offset by benefits for customers who will be able to take advantage of programs that are enabled through the implementation of grid modernization technologies. An example of this is illustrated in the recent results of the Companies' *Annual Status Report* for their *Interim TOU Program* ("TOU-RI").[31] The interim TOU-RI program is intended to provide residential customers with an incentive to change their behavior to better align overall energy consumption with availability of production. By structuring three different rates to correspond with demand periods, participating customers are offered a lower rate (compared to the standard rate) when PV production is generally at its peak (assuming favorable weather conditions) and higher rates during the evening and overnight hours. The annual report showed that the first year of the two-year period revealed an average savings per customer bill of $5.60 per month[32] to TOU-RI participants relative to enrollment on the standard residential rate, as shown in Table 6 below. For program participants, the benefits of this program significantly exceed the projected monthly bill impact from the Phase 1 grid modernization implementation, shown in the Bill Impact section below and detailed in Exhibit I (*Bill Impact*). However, as described in Section E, TOU adoption on a broad scale is not possible without Phase 1's advanced meters, MDMS, and the enabling telecommunications network.

[31] See Docket No. 2014-0192, *Annual Status Report Interim Time-of-Use Program*, filed January 31, 2018.
[32] As expected for a pilot variable rate program, the benefit-cost ratio is significantly under one. Program cost includes the internal accounting of costs associated with deploying the TOU-RI program, programs such as meter procurement and installation, and meter reading and administration. This ratio is due to high costs incurred to administer a program for a relatively small number of participants. A more widely deployed program, taking into account the results of this pilot rate and incorporating changes to the rate, may present a better benefit-cost ratio.

Time-of-Use Rate Impact Costs by Island				
Island	**Aggregate TOU-RI Bill**	**Aggregate Schedule R Bill**	**Total Savings**	**Average Saved per Bill**
O‘ahu	$1,565,625	$1,609,183	$43,558	$4.39
Hawai‘i Island	$322,692	$347,544	$24,852	$11.31
Maui Island	$271,437	$280,261	$8,824	$5.27
Total	**$2,159,754**	**$2,236,988**	**$77,234**	**$5.60**

Table 6

As the Commission approves future programs that fit the State's RPS goals, the Companies anticipate this trend to continue, where customer adoption is enabled by grid modernization investments, with benefits that can include bill reductions through program participation.

As shown in the Revised DR Portfolio filing,[33] a cost-benefit analysis from a robust DR Portfolio should provide net benefits to all customers. The Companies' implementation of the GMS is expected to enable the DR Portfolio (which was approved in D&O 35238) and its associated benefits.

B. CHALLENGES WITH QUANTIFYING BENEFITS

It is impracticable to aggregate GMS implementation benefits for use in a traditional cost-benefit analysis. GMS investments have interrelated and naturally synergistic functions that make it infeasible to determine the cost-effectiveness of each GMS component independently. To compound this, the various benefits enabled by the GMS investments in the accompanying Application (e.g., to support DR and DER) were determined separate from the GMS, in other dockets, using different methods and assumptions.

C. COST-BENEFITS CHARACTERISTICS

Recognizing the foregoing, in the GMS, the Companies proposed a holistic cost-effectiveness framework for evaluating the Companies' grid modernization efforts, as summarized in GMS, reproduced below in Figure 5.[34]

[33] See Docket No. 2015-0412, *Revised DR Portfolio*, filed February 10, 2017.
[34] See GMS, Section 4.2 (Cost-Effectiveness Framework).

Expenditure Purpose Category	Methodology
A. Standards and Safety Compliance Grid expenditures required to ensure reliable operations or comply with service quality and safety standards, including both ongoing asset management (replacement of aging and failing infrastructure) and relevant grid modernization technologies	Lowest reasonable cost (similar to least-cost, best-fit used in other jurisdictions)
B. Policy Compliance Expenditures that are needed to comply with state policy goals like the renewable portfolio standard, or direction to interconnect and enable customer adoption of DER	Lowest reasonable cost
C. Net Benefits Expenditures that are not required for standards and safety compliance or policy compliance but would provide positive net benefits for customers	Total resource cost test
D. Self-Supporting Expenditures incurred for a specific customer (e.g., interconnection), with costs directly assigned to those specific customers.	Only for projects that do not shift a cost burden to non-participants—this category does not require benefit-cost justification.

Figure 5

As illustrated in Table 8 of in the GMS,[35] the Phase 1 advanced metering, headend, and MDMS components fall within the Policy Compliance category and telecommunications falls under the Standards and Safety Compliance category, all of which use the lowest reasonable cost evaluation methodology to determine cost effectiveness.

As described in Exhibit E, the Companies issued RFPs encompassing the major components of Phase 1, including advanced metering, headend, MDMS, and telecommunications. All of the RFPs were developed and evaluated in context with one another and the Companies' broader initiatives, including support of the recently approved DER programs and enterprise-level initiatives. The evaluation of the RFPs includes vendor demonstrations, testing, and assessment to ensure the solutions proposed in each RFP are compatible with each other and consistent with the GMS to ensure that the technology is scalable and compatible in the future to minimize risks of stranded investments. Implementation risk and cost considerations are also being taken into account for each potential combination of vendor solutions. Therefore, the solutions obtained through this competitive procurement process will satisfy the Companies' technology needs (aligned to customer and policy objectives) at the lowest reasonable cost.

[35] See GMS, at 107.

Importantly, as noted in the GMS, the need for a new holistic evaluation framework has also been recognized in other jurisdictions addressing grid modernization.[36] In particular, the California Public Utilities Commission ("CPUC") has an ongoing proceeding examining, among other things, the valuation of customer benefits for grid modernization investments. In its *Staff White Paper on Grid Modernization*, the CPUC staff noted the following difficulties in quantifying benefits to customers:

- Certain technologies are dependent on another technology's capabilities for full functionality. As such, the net benefits of each individual investment may be dependent on the costs and benefits of upstream or enabling technological elements.

- Certain technologies may be necessary for DER integration, but their purpose and the benefits of these technologies are to support safety and reliability on the aging distribution system. The ancillary benefits of safety and reliability should be accounted for, rather than counting the costs entirely against the benefits of DER integration[.]

- Net benefits of Grid Modernization investments differ based on the location at which they are installed. For example, utilities deploy voltage regulators at specific locations to resolve localized power quality problems; while the benefits from system-wide technology deployments are more limited at each site.

- Net ratepayer benefits are dependent on a number costs and avoided costs of enabling DERs and alternate supply side options identified in the Integrated Resource Proceeding.[37]

After receiving stakeholder comment on this white paper, the CPUC recently issued its final Decision 18-03-023 in March 2018.[38] In that decision, the CPUC examined the four potential options for evaluating the cost-effectiveness of proposed grid modernization investments that were posed in the white paper:[39] (1) utilize existing methods, such as customer outage minutes; (2) develop a benefit-cost methodology for grid modernization; (3) apply a least-cost/best-fit framework; or (4) assess net benefits as a component of the Integrated Resource Plan ("IRP") optimization analysis. The CPUC concluded:

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[36] See GMS, at Appendix C, Section 2 (*Literature Review of Grid Modernization Evaluation Methodology in other Jurisdictions*).
[37] See CPUC, Rulemaking 14-08-013 Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769, *Assigned Commissioner's Ruling Requesting Answers to Stakeholder Questions Set Forth in the Energy Division Staff White Paper On Grid Modernization*, issued on May 16, 2017, Attachment: *Staff White Paper on Grid Modernization* (April 2017) ("Whitepaper"), at 29, available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M186/K580/186580403.PDF.
[38] See CPUC, Rulemaking 14-08-013 Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769, *Decision on Track 3 Policy Issues, Sub-Track 2 (Grid Modernization)*, Decision 18-03-023 issued March 26, 2018 (effective March 22, 2018) ("Decision 18-03-023"), at 22-23, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M212/K432/212432689.PDF.
[39] See Whitepaper at 30-33.

To determine the cost effectiveness of each grid modernization investment, the IOUs would need to identify the driver of the investment and **isolate the value of its contribution to enabling DER growth**. **We find this infeasible, given the multiple, interrelated functions of grid modernization investments.**

* * *

[W]e do not find Option 2, the proposal to develop a grid modernization cost effectiveness [benefit-cost] methodology, to be realistic. The **benefits of each grid modernization investment cannot be isolated from the benefits provided by the other grid investments. Instead, the cost-effectiveness of grid modernization needs to be evaluated within the context of the overall cost-effectiveness of the DERs**.

* * *

While we will not require a method to quantify a *cost-effectiveness* showing in order to evaluate grid modernization investments in the GRC, careful vetting of the *cost reasonableness* of these requests remains a critical role for the [general rate case ("GRC")] to meet distribution planning objectives at the lowest possible cost. In their GRCs, the IOUs shall continue to propose the lowest cost approach to meeting these grid needs, and should provide an explanation for what is causing the need for each type of investment as part of the GRC submission requests. We find that current GRC approaches are effective and appropriate, and should continue to be used.

With the exception of Option 2 in the White Paper, we find that all of the remaining approaches play an important role in determining the appropriate levels of investment in DER integration, and that Options 1 and 3 are currently used to review distribution funding requests. The most appropriate approach to evaluate the cost reasonableness depends on what drives an investment: (1) to integrate and maximize the value of DERs, (2) to mitigate forecasted safety and reliability challenges based on either growth of DERs, or growth in demand, or (3) combination of these drivers.

Option 1 applies to distribution upgrades that improve safety and reliability, and is currently used in GRCs to evaluate proposed distribution investments. IOUs should continue to apply traditional reliability metrics, such as the system average interruption duration index (SAIDI) wherever applicable.

Option 3 proposes that the IOUs identify the lowest cost approach to meeting grid needs and present alternative options. This

> standard of evaluation may apply to investments driven by DER integration or by safety and reliability mitigation, and should be addressed whenever alternative options are available.
>
> Option 4 will occur in the IRP proceeding, and will inform future DER sourcing policy and IEPR growth forecasts.[40]

This method of evaluating grid modernization cost-effectiveness based upon the type of investment being evaluated is analogous to the evaluation process set forth in Section 4.2 of the GMS.[41]

In Decision 18-03-023, the CPUC found, among other things, that:

> 10. The benefits of each grid modernization investment cannot be isolated from the benefits provided by the other grid investments.
>
> 11. The cost of grid modernization should be considered within the context of the overall cost-effectiveness of the DERs.[42]

The CPUC went on to order, among other things, that:

> The cost of grid modernization shall be considered within the context of the overall cost-effectiveness of Distributed Energy Resources (DER). The Commission will evaluate the cost effectiveness of DERs and establish the procurement policies to optimize the resource mix in the Integrated Resource Planning and Integrated Distributed Energy Resource proceedings.[43]

The CPUC decision is complimentary with the U.S. Department of Energy Distribution System Platform (DSPx) decision guide and cost-effectiveness framework, which outlines recommended application of least-cost / best fit method, traditional customer benefit-utility cost, integrated power system & societal benefit-cost, and real option analysis approaches for grid modernization investments.[44]

For the Companies' GMS, where the Phase 1 application and its associated RFP process required the Companies to evaluate and consider alternative technology options to meet GMS

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[40] Decision 18-03-023 at 24-27 (bolding added, italics in original). The CPUC's IRP is similar to the Companies' PSIP (see Decision 18-02-018 at 10-11).
[41] See GMS, Section 4.2 (Cost-Effectiveness Framework).
[42] Decision 18-03-023 at 32.
[43] Id. at 36, para. 6. The CPUC's IDER is "a strategy that seeks to provide comprehensive building energy management solutions via the integration of technologies, programs, and strategies to facilitate customer behavior changes that reduce load and grid inefficiencies." CPUC, Integrated Distributed Energy Resources, available at http://www.cpuc.ca.gov/General.aspx?id=10710.
[44] See U.S. Department of Energy Office of Electricity, *Modern Distribution Grid (DSPx) Decision Guide Volume III* (June 28, 2017), at Section 3.4.1 (Cost-Effectiveness Framework), available at https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx.

policy objectives, Option 3 (least cost / best fit) would apply under the CPUC framework, which is similar to the lowest reasonable cost approach proposed by the Companies. Moreover, similar to the approach proscribed by the CPUC in California, the Companies propose that the cost of Phase 1 of the GMS should be evaluated in consideration of the collective benefits derived from customer energy options described above.

This approach is also consistent with the new IGP process, which will consider a full range of options and more effectively evaluate the final set of short-term solutions to meet Hawai'i's resource, transmission, and distribution needs. This approach avoids the need to conduct cost effectiveness analysis outside of the resource planning process, as was typically done in the past. IGP will need to learn from and inform other ongoing activities and relevant proceedings, including programs such as DER, DR, CBRE, EoT, and ongoing grid modernization projects.

D. ADDITIONAL PROGRAMS AND INITIATIVES

The breadth of GMS enabled customer energy options is continuing to grow and the need for GMS investments in the accompanying Application is becoming more important as additional new programs and initiatives move forward, including EoT, CBRE and Smart Cities.

1. EoT

The Companies' recently filed EoT Strategic Roadmap indicated that:

> Advanced meter data will support accurate forecasts of EV load growth and help Hawaiian Electric understand how to motivate managed and daytime charging to facilitate integrated planning with renewable generation and distribution planning.
>
> This will create value for EV drivers and non-EV drivers alike by enabling improved customer engagement and experience with the grid, supporting efficient and reliable distribution planning, enabling the design and targeting of smart charging programs, and using EVs to more fully integrate renewable generation.[45]

These smart charging programs would be enabled by the proposed Phase 1 GMS platform investments inclusive of advanced meters, MDMS, and a FAN-based telecommunications network. Within the EoT Strategic Roadmap, the Companies included an analysis that smart charging strategies would result in a 53% improvement in the net customer benefit per vehicle.[46]

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[45] See Docket No. 2016-0168, *Electrification of Transportation Strategic Roadmap*, filed March 29, 2018, at 101.
[46] See id. at 35.

2. CBRE

More resources are being added to the grid through new programs that continue to require the functionality that rely on the GMS technology necessary to facilitate integration and manage system reliability. This need is greater still with the development of CBRE programs. CBRE projects will be relied upon to provide necessary capacity and grid services in order to meet the State's RPS goals. Some CBRE projects will also be equipped with grid-modernization deployed communication and control features such that the Companies can ensure the safe and reliable operation of both the generating facility and the grid.[47]

3. Smart Cities

As stated in Section 6.5 of the GMS, many cities and communities around the country are participating in a dialogue about how to leverage technology innovations to transform themselves into "smart cities." These smart cities would be interconnected via the Internet of Things and allow a free flow of data that can both enhance existing city functions as well as create new ways to positively impact the communities they serve. Furthermore, convergence of networks can create strong economic benefits for communities, businesses, and customers as well as for the various infrastructure owners. The opportunity to collaborate with different entities and converge multiple networks arises from the potential to integrate various elements of the respective networks or systems. The convergence of the electric network with other critical infrastructure, along with social and economic networks, is an opportunity that will be enabled through a modern distribution system as envisioned in the GMS and would establish a platform for convergence opportunities in the future. Not only will this provide synergistic opportunities, it will bolster capabilities to provide communities with resiliency and sustainability by partnering with agencies that can contribute to those additional characteristics. The Companies will keep cybersecurity, data security and customer information confidentiality and privacy at the forefront of consideration when exploring these smart city opportunities.

E. IMPROVED METER FUNCTIONALITY AND EFFICIENCY

Manual meter reading is not sustainable to support customer energy options. Therefore, advanced meters are necessary to support customer energy options with initial meter deployments supporting the recently approved Smart Export and CGS+ programs[48] and the DR Portfolio.[49] The "smart production meter" capability for the CGS+ program requires advanced meters that have communicating capabilities.[50] Additionally, customer energy options to provide grid services will utilize interval usage meter data to perform measurement and verification of resource performance and/or the enabling tariff structures.

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[47] See Docket No. 2015-0389, *Application For Approval to Establish a Rule to Implement a Community-Based Renewable Energy Program*, filed October 1, 2015. The CBRE program may utilize the GMS implementation infrastructure to enable benefits for smaller projects.
[48] See Docket No. 2014-0192, D&O 34924, issued October 20, 2017.
[49] See Docket No. 2015-0412, D&O 35238, issued January 25, 2018.
[50] See Docket No. 2014-0192, D&O 34924, issued October 20, 2017, at Section VI, *Findings and Conclusions Number 51 and 52*.

In further assessing the proper approach to deploy the components of Phase 1, the Companies took into consideration existing meter platforms currently configured on the electric grid to determine the gaps in functionality, workflow and efficiencies. These assessments showed what would need to be addressed to enable the vision of grid modernization and then identified that the advanced meters, MDMS, and telecommunications network infrastructure were required.

Figure 6, below, illustrates the relatively basic metering requirements to enable the legacy net energy metering ("NEM") program where three meter registers are read manually: (1) register 03 records the energy received from the grid; (2) register 33 records the excess energy sent to the grid; and (3) register 23 records the net energy (register 03 minus register 33).

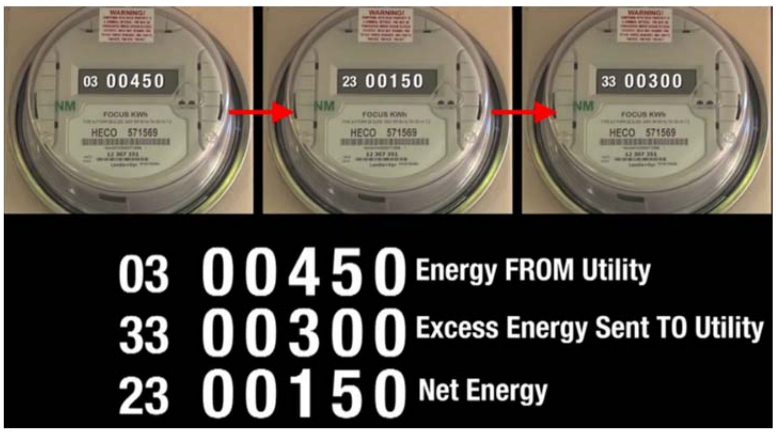

Figure 6

Figure 7 below, illustrates the meter situation for the Smart Export program, which requires that nine registers be manually read: (1) the three registers utilized for NEM totalized across 24 hours; (2) the three registers for the 4 p.m.–9 a.m. time period; and (3) the three registers for the 9 a.m.–4 p.m. time period.

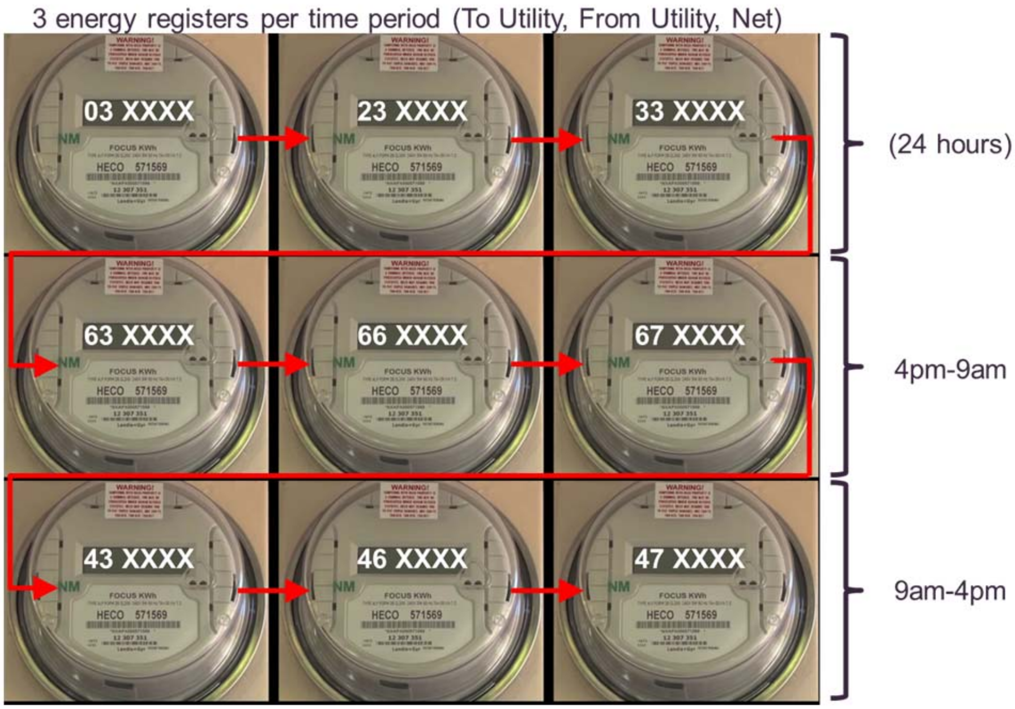

Figure 7

Figure 8 below, shows how this kind of meter read would apply as tariffs become more complex, such as for the TOU non-demand with the NEM program and the similar TOU EV program. In these programs, twelve registers must be manually read, which is beyond the capability of a single non-advanced meter and would require a combination of two meters to have enough meters to read: (1) the three registers utilized for NEM totalized across 24 hours; (2) the three registers for the 5 p.m.–9 p.m. time period; (3) the three registers for the 7 a.m.–9 p.m. time period; and (4) the three registers for the 9 p.m.–7 a.m. time period.

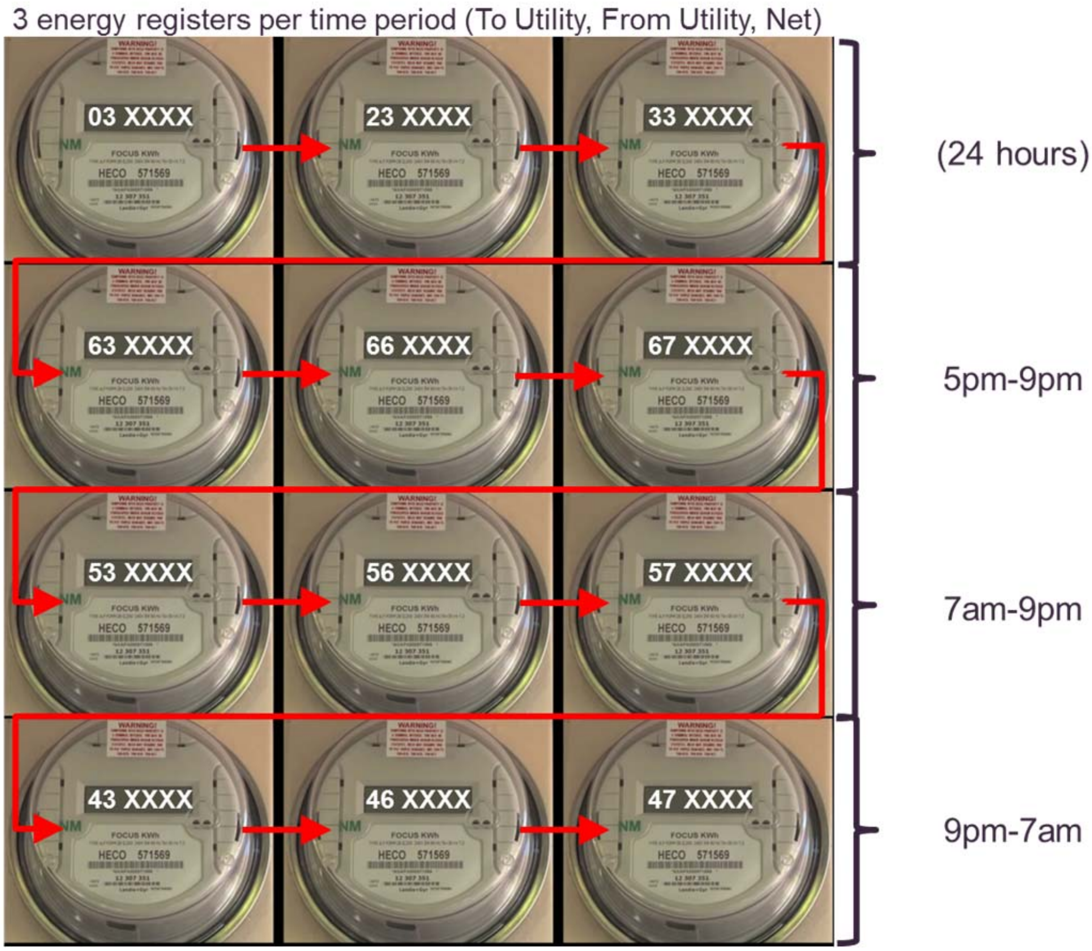

Figure 8

The figures above highlight the unsustainable inefficiency of the manual meter reading workflow that would be required without advanced meters to support the growth of increasingly complex tariffs, rates, and incentive programs that enable customer energy options. For example, reading a register manually takes four seconds on average. Therefore, reading a meter supporting basic NEM manually takes 12 seconds. Manually reading 12 registers divided between two meters to provide enough data to create a TOU non-demand with NEM billing statement would take at least 48 seconds. In addition, the process of manual reads is increasingly subject to error as the complexity of the registers increases – especially if the meter data is divided between two different meters.

The advanced meters being proposed as part of Phase 1 will likely be configured to read data in five-minute intervals and communicate that interval read data to the Companies multiple times per day without manually being read. This greater efficiency and resolution of data will provide more insight to refine load forecasts and better understand DER demand and export variability. The interval usage data will be stored in the MDMS, which is used to calculate the more complex billing-determinate data for DER and future TOU rates, as well as provide data to

the DRMS (which performs measurement and verification for the settlements required for DR participants) and to verify the alignment of DR performance with aggregator contracts.[51]

Another way to view this would be to examine the billing determinants, which are used for the billing application within the CIS to query the MDMS for each of the calculations that currently require a specific meter register to record the cumulative data for billing purposes. As illustrated in Figure 9, below, with a TOU-EV rate, CIS would query the MDMS to calculate the total "from utility," "to utility," and "net" usage from 5 p.m.–9 p.m., 7 a.m.–9 p.m. and 9 p.m.–7 a.m. for a specific billing period based on five-minute-interval data recordings. To illustrate the flexibility of this approach, the parameters for the query to the MDMS can be changed rather than needing to reprogram the meter register parameters, if at some point in the future the program's time periods change.

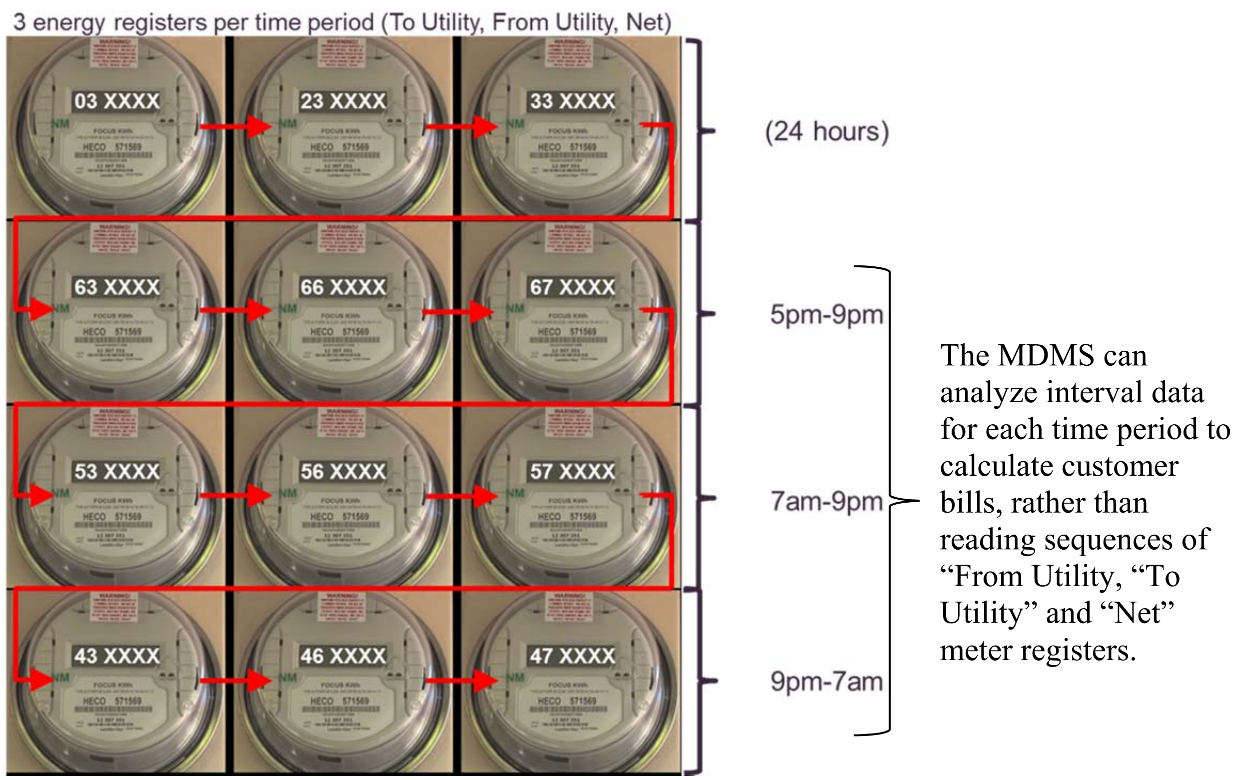

Figure 9

Due to the manual reading inefficiencies explained above, another alternative is the use of a load profile meter (without communications) that records interval data, as was done in the interim TOU-RI pilot program. However, this option is more costly and less efficient. The cost of a load profile meter is similar to that of an advanced meter (less the communication card), and although it records interval data, it does not have communications capability, nor does it provide customers a means to monitor usage at a granular hourly level on a regular basis through a customer energy portal. Furthermore, to download monthly interval data, a meter reader spends on average about 5-7 minutes downloading information from the load profile meter though an

[51] See Docket No. 2015-0412, *Response to PUC-IR-112*, filed July 13, 2017, at 2.

optical port. As was stated in the interim TOU program annual status report[52], a potential program size of 5,000 meters equates to approximately 30,000 minutes per year or 1/4 person per year resource dedicated to downloading data alone.

As shown in these examples of current and future program challenges and inefficiencies, investments in advanced meters, an MDMS, and a telecommunications network infrastructure will provide required data in appropriate intervals that will be collected efficiently and accurately. Furthermore, customer utilization of the information needs to be readily available (not after the fact a month later), to allow customers to make choices on a regular basis to fully utilize the benefits of any particular customer energy option.

F. BETTER MONITORING AND CONTROL

The Companies also agree with the CPUC's statement in Decision 18-03-023, discussed above, that:

> [A] separate evaluation of proposed grid modernization investments for DER integration, without consideration of the safety and reliability impacts, would not be feasible. The Grid Modernization Guidance shall apply to all investments that are related to DER integration, including investments that are also driven by safety and reliability needs.[53]

This is consistent with the cost effectiveness framework set forth in Section 4.2 of the GMS, specifically related to improved reliability, safety and/or operational efficiency (Standards and Compliance). As part of the CPUC decision, the definition of grid modernization was adopted as follows:

> A modern grid allows for the integration of distributed energy resources (DERs) **while maintaining and improving safety and reliability**. A modern grid facilitates the efficient integration of DERs into all stages of distribution system planning and operations to fully utilize the capabilities that the resources offer, without undue cost or delay, allowing markets and customers to more fully realize the value of the resources, to the extent cost-effective to ratepayers, while ensuring equitable access to the benefits of DERs. **A modern grid achieves safety and reliability of the grid through technology innovation** to the extent that is cost-effective to ratepayers relative to other legacy investments of a less modern character.[54]

One of the safety and reliability concerns the Companies face today is the changing voltage conditions inherent in two-way electrical distribution. In areas with a high penetration of DER, the Companies have recorded voltage issues where voltages are approaching or exceeding

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[52] See Docket No. 2014-0192, *Annual Status Report Interim Time-of-Use Program*, filed January 31, 2018, at 28.
[53] See CPUC, Decision 18-03-023, at 6.
[54] Id. at 33 (emphasis added).

the ±5% range from service voltage standards established by ANSI C84.1[55] and mandated by General Order No. 7, *Standards for Electric Utility Service in the State of Hawaii*, and the Companies' Rule No. 2, *Character of Service*. For example, the range of acceptable voltage for 120V service is 114V to 126V, and 228V to 255V for 240V service.

The visibility that the Companies expect to acquire from advanced meters will increase the utilization of the meter investment in three key ways: (1) by improving customer service through quicker identification of power quality (high or low voltage) issues, whether caused by DER or grid equipment/design, (2) by providing more accurate information to support the DER interconnection process through quick identification of voltage "hotspots" on secondary system, and (3) by enabling more granular information to improve modeling simulations that will support IGP efforts.

To realize the benefits stated above, visualizations of meter data can be helpful for planners and operators to assess the grid's condition or a particular customer's situation to determine whether it is safe to interconnect a PV system, or whether the Companies' should proactively modernize sections of a grid. For example, Figure 10 below shows analysis from smart meter data obtained from the SGF initial phase installation; this demonstrates how meter data can be visualized to quickly identify "hotspots" (shown in the colored dots), which could be areas with potential voltage issues.

[redacted]

Figure 10

Additionally, the meters will complement the tactical deployment of line sensors to monitor distribution feeder voltage. With the addition of the ADMS contemplated as part of the

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[55] See National Electrical Manufacturers Association (NEMA), *American National Standard for Electric Power Systems and Equipment—Voltage Ratings (60 Hz)*, Document ID: 100277, ANSI C84.1-2016 available at https://www.nema.org/Standards/Pages/American-National-Standard-for-Electric-Power-Systems-and-Equipment-Voltage-Ratings.aspx.

Phase 2 grid modernization funding application, the meters are a key component to executing and optimizing the Companies' three-prong voltage management strategy to increase DER hosting capacities.[56] The three-prong strategy described in the GMS includes: first, leveraging autonomous advanced inverter functions through the activation of volt-var and volt-watt, aligning asset management programs with DER needs, and optimizing voltage regulating equipment settings; second, company investments in secondary var controllers ("SVCs") in areas where voltage issues persist; and, third, if power quality issues remain, execute traditional circuit upgrades.[57]

These circuit modification or investments can only be optimized through having an end to end picture of a circuit's voltage profile (e.g., from the substation to the distribution transformer, down to the customer). If system operators and planners do not have visibility down to the customer level, it would be virtually impossible to optimize voltages to the edges of the aforementioned ANSI standard limits. With the added visibility from advanced meters, the Companies' may be able to reduce investments in SVCs or circuit upgrades and further increase hosting capacities for customers. For example, when optimizing circuit voltages, there may be one outlier cluster of customers that may prevent the Companies' from realizing additional hosting capacity because that one group of customers are at the margins of the ANSI limits. Through voltage readings at those customers' meter, the Companies' could mitigate that outlier and therefore, optimize the voltage for the entire circuit.

In addition, the advanced meters' connect and disconnect functionality provides "smart production meter" capability for the CGS+ program.[58] This connect and disconnect functionality is traditionally used in the industry to facilitate customer move-in and move-out requests and, in some instances, to disconnect customers for nonpayment after all required collection attempts and communications have been completed. In some instances, the daytime minimum load served by the Companies requires turning off or inefficiently ramping down some central generation because the minimum output from those central resources combined with the output from DER exceeds customer demand for electricity. With sudden changes to DER output or customer demand, system issues can occur and result in customer outages. Utilizing the advanced meter disconnect to control the DER output from CGS+ customers will potentially reduce the number of outages caused by system stability issues by facilitating targeted curtailment of DER export and increasing reliability. Note that this functionality depends on coordination of a supporting communications and back office systems to support it and is not solely a function of the advanced meters, as discussed in Exhibit A.

G. MDMS DATA EXCHANGE

The initial benefit of the MDMS is its ability to analyze interval usage and demand data. These analytical functions can support operational processes across the Companies, from balancing and planning the modern grid to meeting customer expectations and calculating modern incentive structures. The interval meter data stored in the MDMS provides the data and

[56] See GMS, at 89-92.
[57] See id.
[58] See Docket No. 2014-0192, D&O 34924, issued October 20, 2017, at Section VI, *Findings and Conclusions Number 51*.

flexibility for the design and implementation of future customer energy options. To support the time resolution needed for DR to be a system resource, as well as provide insight for distribution system planning, the default advanced meter recording interval will be five minutes. To support potential future needs, both the meter and MDMS requirements specify one-minute interval capabilities.

VII. BILL IMPACT

As detailed in Exhibit I, the average monthly bill impact for typical residential customers using 500kWh is summarized below. Compared to the TOU-RI pilot or other programs, the bill impact will be a savings for customers who enroll in programs that utilize these GMS investments.

- $0.24 at Hawaiian Electric, ranging from $0.01 to $0.59;
- $0.34 at Maui Electric, ranging from $0.05 to $0.87; and
- $0.55 at Hawai'i Electric Light, ranging from $0.05 to $1.18.

The bill impacts shown above reflect a 30 year period for Phase 1. The bill impact excludes Phase 2 and other future replacement costs. Beyond Phase 1 (2023), the Companies will need to continue to invest in and modernize the grid. At this time the scope and scale of this future effort are not known. Technology is evolving at a rapid pace. As a result, the Companies will need to assess the needs of the customers and the grid in order to pair the appropriate technology that is available. Replacements will be included in future filings or rate cases.

In D&O 34924 approving the CGS+ and Smart Export programs, the Commission stated that the costs of the advanced meters are to be borne by all ratepayers. The issue of cost causation was raised by the Consumer Advocate and other external stakeholders, specifically when it came to the issue of costs related to the advanced meter, which is higher in cost than standard meters. The Commission noted:

> While the commission generally agrees with the Consumer Advocate that "costs should follow the causer," the commission finds that the circumstances here, including the system-wide benefits anticipated from the data collection from the meters, controllability offered to the utility, and relatively small size of the program, justify recovering the costs of the smart production meters from ratepayers.[59]

The points noted by the Commission are acknowledged. Therefore, this initial application includes the cost for the advanced meters to support forecasted customer participation in the recently approved Smart Export, CGS+ and DR Portfolio in addition to costs for new meter sets and replacement meters with the understanding that the GMS costs will be

[59] See Docket No. 2014-0192, D&O 34924, issued October 20, 2017, at 136.

borne by all customers. Stakeholders have suggested that there are system-wide benefits for all customers as well as individual benefits for customers participating in customer energy options, and some have noted that a percentage of the advanced meter costs should be allocated between individual customers who have benefitted from program adoption and customers who have benefited from the system-wide benefits. Because of the complicated nature of this discussion as it relates to rate design and impacts to issues in numerous other dockets, the Companies believe this issue should be addressed in another docket, such as the Market Track phase of the DER proceeding (Docket No. 2014-0192). Additionally, because the Companies cannot predict future development and adoption of customer energy options, the costs for the advanced metering to support future programs should be taken into account when evaluating the program costs and benefits. Moreover, the incremental cost for deploying advanced metering to support future programs should be included in the costs to enable the program – even if the Commission determines that the cost should be borne by all customers.

VIII. CONCLUSION

A modern, reliable and resilient electric grid is needed to provide the foundation for delivering the benefits of the Hawaiian Electric Companies' current and future programs that are enabling customer value and helping to achieve Hawaiʻi's RPS goals. Beginning with the GMS Phase 1 Project, the platform developed and deployed as part of the GMS will drive the grid toward achieving more renewable integration, enable more customer energy options, and enable exploration of alternatives to meet the needs and expectations of Hawaiʻi's communities and stakeholders. Without the investments described in the GMS, customer choice will be limited and already-approved customer energy options and their respective benefits will not be fully realized.

Phase 1 of the GMS consists of: (1) the proportional deployment of advanced meters; (2) implementation of an MDMS; and (3) installation of a telecommunications network. Together, these investments will play an integral role in building a modern electric grid for Hawaiʻi by, among other things, serving as key enablers of the already-approved Smart Export, CGS+ and DR programs. The foundational groundwork laid in connection with the Phase 1 Project will also support future customer energy options and systems, such as EoT, CBRE, Smart Cities and the implementation of an ADMS.

The total estimated cost of the Phase 1 Project is approximately \$86.3 million, which will result in modest average bill impacts of \$0.24, \$0.34 and \$0.55 for typical residential customers at Hawaiian Electric, Maui Electric and Hawaiʻi Electric Light, respectively. Although it is impracticable to aggregate GMS implementation benefits for use in a traditional cost-benefit analysis, Phase 1 is expected to be cost-beneficial under a lowest reasonable cost analysis and when considered in the context of enabling distributed customer energy options that can provide more cost-effective alternatives to traditional wired investments. For example, the overall GMS implementation has been estimated to be \$121 million more cost-effective than the wires alternative estimated in the Companies' PSIPs.

By employing a targeted approach to carrying out Phase 1 in an as-needed, where-needed manner, the Project will maximize customer value by supporting energy options and mitigating implementation risks. Over time, as more field devices and advanced meters are deployed in the

Companies' service territories, the technologies and systems proposed through the progression of GMS phases will enable system operators to engage with the Companies' DER and DR programs to maintain grid stability, thereby providing further benefits to customers.

Exhibit C

GMS Phase 1 Application

Accounting and Ratemaking Treatment

Note: References to exhibits in this document refer to exhibits included in the accompanying application unless otherwise noted.

ACCOUNTING & RATEMAKING TREATMENT

The Hawaiian Electric Companies[1] propose the following accounting and ratemaking treatment specific to the accompanying Grid Modernization Strategy's ("GMS") Phase 1 ("Phase 1") application.

Phase 1 of implementing the GMS is a foundational project involving interrelated components consisting of traditional capital expenditures, which include equipment and the associated cost of installing the equipment, computer hardware and related software, software development, software services, and significant interconnection and integration to enable the full benefits of this project and future programs.

The proposed accounting for Phase 1's foundational components generally follows the accounting for capital expenditures and software projects approved by the Public Utilities Commission ("Commission") in the past. In general, the cost of equipment and hardware will be capitalized and its related software and development costs for the project will be deferred. Such treatment is in accordance with Generally Accepted Accounting Principles and consistent with the Companies' current accounting for such costs. Costs related to software development for Phase 1 and system integration work will follow the Companies' existing accounting policy, which is consistent with the Accounting Standards Codification ("ASC") 350-40, "Internal-Use Software,"[2] of the Financial Accounting Standards Board ("FASB").

The proposed accounting for each of the foundational components of Phase 1 is described below.

I. ADVANCED METERS

The advanced meters component consists of traditional capital expenditures, computer hardware and software development, configuration, and implementation costs.

A. CAPITAL COSTS

The Companies will capitalize the equipment and installation costs associated with the new advanced meters and associated warranty costs (meters are pre-capitalized utility assets) upon receipt and acceptance by the Companies.

The following general accounting assumptions will be used as part of the deployment and implementation of the advanced meters during Phase 1:

[1] Hawaiian Electric, Hawaiʻi Electric Light and Maui Electric are collectively referred to as the "Hawaiian Electric Companies" or the "Companies."
[2] Formally known as Statement of Position 98-1, "Accounting for the Costs of Computer Software Developed or Obtained for Internal Use," issued in March 1998.

- The Companies propose to depreciate the new advanced meter costs using the latest Commission-approved depreciation rate for meters, beginning January 1 following the year the meters are capitalized. The Companies will address the impact to the meter depreciation rate and average service life as a result of the advanced meters in the Companies' next depreciation study.

- Hawaiian Electric will capitalize the hardware (servers) related to the advanced meter headend provided by the selected vendor. The hardware costs will be amortized over five years using the Companies' latest Commission-approved amortization for computer equipment beginning January 1 following the year the hardware is capitalized. The amortization of the computer equipment will be allocated between the Companies with 70% recorded to Hawaiian Electric and 15% billed to each of Maui Electric and Hawaiʻi Electric Light.

Depending on the respective utility, the capital costs incurred outside of rate case test years are proposed to be recovered through the Major Projects Interim Recovery ("MPIR") adjustment mechanism ("Mechanism") until such costs are reflected in base rates, while the costs incurred during rate case test years are proposed to be recovered through the base rates established in the Companies' respective rate cases, as discussed in Exhibit D (*Interim Recovery*).

B. DEFERRED COSTS

The Companies request to defer costs for the implementation of the meter headend system. These deferred costs include the following: (1) the purchase, installation, and configuration of the meter headend software by the vendor, and (2) third-party consultants to perform the development of the required system integration with new and legacy systems and testing of the new processes being implemented. The costs that will be deferred include an allowance for funds used during construction ("AFUDC") during the implementation phase. The deferred software implementation costs will be consistent with ASC 350-40, under which portions of the implementation costs are deferred and other portions of the software implementation costs (such as end-user training, overhead costs not payroll-related, and post-implementation costs) are expensed as incurred. As allowed under ASC 350-40, the deferred costs would accrue AFUDC.

The deferred costs will be amortized over 12 years in each respective company's rate case, beginning the month following the date the software is placed in service, and the unamortized costs will be included in the rate base (see Exhibit D)

Depending on the respective company, the deferred costs added to plant outside of rate case test years are proposed to be recovered through the MPIR Mechanism until such costs are reflected in base rates, while the costs added to plant during rate case test years are proposed to be recovered through the base rates established in the Companies' respective rate cases. If the commission is not inclined to allow recovery of deferred costs through MPIR Mechanism, alternate options proposed for recovery include recovery through the Renewable Energy Infrastructure Program Surcharge ("REIP Surcharge"), or through future base rates (see Exhibit D).

C. EXPENSE COSTS

The Companies will expense the firmware maintenance expenses, operational support, troubleshooting, analysis, and implementation costs that cannot be deferred (such as end-user training, overhead costs not payroll-related, and post-implementation/stabilization costs), any software-as-a-service ("SaaS") fees, and the miscellaneous costs for the advanced meters related to cellular services required for communications between the meters and the Companies' back office systems. To the extent that these costs are not recovered in current rates, the Companies plan to address recovery of these costs in future rate cases. A schedule for each utility's future rate case is provided in Exhibit D.

D. EXISTING AND REPLACED METERS

The Companies will continue to depreciate and account for the existing meters over the current Commission-approved depreciation rates and include them as utility assets until the meters are retired. Consistent with the Companies' current practice, no gain or loss will be recognized on the retirement of the existing meters.

The GMS is deploying advanced metering via an "opt-in" approach, which is in contrast to prior applications by the Companies that sought to deploy advanced meters to all customers. Due to this approach, the Companies are not requesting special accounting treatment for replaced meters. Meters that are replaced by advanced meters will continue to depreciate using the current Commission-approved depreciation rate.

II. METER DATA MANAGEMENT SYSTEM

The cost of the Meter Data Management System ("MDMS") consists of capital costs, deferred costs, and expenses.

A. CAPITAL COSTS

The Companies will capitalize the MDMS hardware. The new hardware will be included in plant-in-service upon installation and amortized over five years, beginning January 1 of the year following the installation of the hardware. This is consistent with the Companies' latest Commission-approved amortization period for computer equipment.

Depending on the respective utility, the capital costs incurred outside of rate case test years are proposed to be recovered through the MPIR Mechanism until such costs are reflected in base rates, while the costs incurred during rate case test years are proposed to be recovered through the base rates established in the Companies' respective rate cases, as discussed in Exhibit D.

B. DEFERRED COSTS

The Companies propose to account for the MDMS software development costs similar to the accounting for software development costs under FASB ASC 350-40, under which specific implementation costs are deferred and other portions of the implementation costs (such as end-

user training and overheads not related to payroll) are expensed as incurred. As allowed under ASC 350-40, the deferred costs would accrue AFUDC.

The Companies request to defer costs for the implementation of the MDMS. These include costs for: (1) software purchase and the vendor resources to install and configure the system per the requirements in the MDMS RFP; (2) third-party system integrators (which were not part of the RFP) required due to the complexity of the integration to connect the MDMS with the metering, billing, and demand response management systems; and (3) contract labor resources to supplement the workforce in the testing and validation of the new work processes being implemented. These deferred costs will be amortized over 12 years, beginning the month following the date the software is placed in-service, and the unamortized costs will be included in the rate base (see Exhibit D).

Depending on the respective company, the deferred costs added to plant outside of rate case test years are proposed to be recovered through the MPIR Mechanism until such costs are reflected in base rates, while the costs added to plant during rate case test years are proposed to be recovered through the base rates established in the Companies' respective rate cases. If the Commission is not inclined to allow recovery of deferred costs through MPIR Mechanism, alternate options proposed for recovery include through the REIP Surcharge, or through future base rates (see Exhibit D).

C. EXPENSES

The Companies will record and recognize the MDMS-related expenses (e.g., end-user training, support, and maintenance related to the software development work) and miscellaneous office supplies as incurred. To the extent that these costs are not recovered in current rates, the Companies plan to address recovery of these costs in future rate cases. A schedule for each utility's future rate case is provided in Exhibit D.

III. TELECOMMUNICATIONS NETWORK

The telecommunications network component consists of traditional capital expenditures, computer hardware, configuration, and implementation costs.

A. CAPITAL COSTS

- The Companies will capitalize the equipment and associated installation costs for the ancillary facilities necessary to build and support a radio frequency mesh network for the Field Area Network. The mesh will enable the meters and future sensing and distribution automation equipment to communicate with the back office systems. These costs will be amortized over 15 years consistent with the Companies' latest Commission-approved amortization for communication equipment, beginning January 1 following the year they are placed in service.

- Hawaiian Electric will capitalize the hardware (servers) and operating software related to the telecommunication headend provided by the selected vendor. The hardware costs will be amortized over five years consistent with the Companies' latest Commission-approved amortization for computer equipment, beginning

January 1 following the year the hardware is capitalized. The amortization of the computer equipment will be allocated between the Companies, with 70% recorded to Hawaiian Electric and 15% billed to each of Hawaiʻi Electric Light and Maui Electric.

Depending on the respective company, the capital costs incurred outside of rate case test years are proposed to be recovered through the MPIR Mechanism until such costs are reflected in base rates, while the costs incurred during rate case test years are proposed to be recovered through the base rates established in the Companies' respective rate cases, as discussed in Exhibit D.

B. EXPENSES

The Companies will expense the firmware maintenance expenses, operational support, troubleshooting, analysis and implementation costs, any SaaS fees, and the miscellaneous costs for the telecommunications network related to cellular services required for communications between the meters, access points, and the Companies' back-office systems. To the extent that these costs are not recovered in current rates, the Companies plan to address recovery of these costs in future rate cases. A schedule for each utility's future rate case is provided in Exhibit D.

IV. EXISTING ACCOUNTING POLICY FOR SOFTWARE PROJECT COSTS

In Decision and Order No. 18365, filed February 8, 2001, in Docket No. 99-0207 (*Hawaiʻi Electric Light 2000 test-year rate case*), the Commission ruled that preapproval is required before any computer software development project cost can be deferred and amortized for ratemaking purposes. In accordance with the Commission's ruling, the Companies are not deferring and amortizing software development costs for ratemaking purposes unless prior Commission approval is obtained. In addition, in obtaining approval to defer software development costs for the Companies' Customer Information System ("CIS") project in Docket No. 04-0268, the Companies and the Consumer Advocate reached a stipulated agreement, filed on April 13, 2005, and subsequently approved in Decision and Order No. 21798 of said docket. See Attachment 1 for the Companies' existing accounting policy for software project costs.

The Companies have been following their existing accounting policy (the proposed ratemaking policy is the same), consistent with FASB ASC 350-40, "Internal-Use Software," as follows:

- Hardware costs would be capitalized, while software costs would be either expensed or deferred, depending on the type of work performed during each stage of the project.
    - *Stage 1 – Preliminary Project:* Includes conceptual formulation of alternatives, evaluation of alternatives, selection of the new system, and the selection of a consultant to assist in the development/installation of the selected product. These costs are expensed.
    - *Stage 2 – Application Development:* Includes the design of a chosen path, installation, configuration, testing of software, and parallel processing.

These costs are generally deferred and amortized.[3] Note, however, that external and internal training costs, as well as certain conversion costs, are expensed.

- *Stage 3 – Post-Implementation Operation:* Includes training and application maintenance costs. These costs are expensed.

- AFUDC would be applied to the deferred costs during Stage 2.

- The deferred costs would be amortized over a 12-year period (or such other amortization period that the Commission finds reasonable) to the appropriate operations and maintenance expense account(s), based on the benefiting organization. The amortization period would begin in the month after the computer software is ready for intended use after all substantial testing is completed. Under the accounting guidance of FASB ASC 350-40, the amortization period for software development costs should be the expected useful life of the developed software. This is consistent with the Commission-approved amortization periods of the Companies' other deferred software development projects.[4]

- Unamortized deferred costs (including AFUDC) would be included in the calculation of the rate base.

- Certain overhead costs, other than payroll and payroll-related costs, will be identified, tracked, and reclassified to expense on a monthly basis, to the extent these costs are included in the deferred costs.

- In order to properly track the project costs and ensure consistency with the financial accounting policy presented here, the Companies will:

    - Establish a project hierarchy to allow for the tracking of project costs based on the project stages as described above; and

    - Work with the vendors selected to ensure sufficient information and activity descriptions are available to support the vendor invoices and to ensure the costs are properly posted and recorded.

[3] Deferral of such expenses for ratemaking purposes would be subject to Commission approval. Such approval would apply to the applications of AFUDC to deferred costs and the inclusion of unamortized deferred costs in the rate base.

[4] The expected useful lives of the Companies CIS, Outage Management System ("OMS"), and Human Resource Management System ("HRMS") projects were estimated at 10, 10, and 7 years, respectively. However, as part of the settlement agreement in the OMS and CIS proceedings, the Companies agreed to utilize a 12-year amortization period proposed by the CA. To be consistent with those projects, the Companies proposed a 12-year amortization period for the HRMS project.

Attachment 1

GMS Phase 1 Application

Exhibit C

Accounting for the Costs of Computer Software

ACCOUNTING FOR THE COSTS OF COMPUTER SOFTWARE DEVELOPED OR OBTAINED FOR INTERNAL USE

(Updated as of April 1, 2006)

Introduction

The following guidelines are provided to assist in the accounting for computer hardware and software costs (acquired, internally developed, or modified solely to meet the entity's needs). This is not meant to be all-inclusive, however we will continue to add or revise the information below, as needed, to provide additional clarification. Questions with respect to these guidelines should be addressed to the Controller or Director of Corporate and Property Accounting.

As a general rule, the costs of computer software, including applicable labor to install the software, and ongoing maintenance are generally charged to the appropriate functional operation and maintenance (O&M) expense account(s), i.e. expensed as incurred, based on the benefiting organization unless:

1. Deferrable software costs have been identified in accordance with applicable accounting standards AND approval has been obtained from the PUC allowing the Company to defer those costs,
2. The computer software is an operating system-type (e.g., Windows XP) software needed to render the new computer hardware "used or useful",
3. Specific overhead costs allowed to be applied to deferrable software costs,
4. AFUDC on deferrable software costs.

Costs for software development projects less than $500K would generally be expensed as incurred. (The $500K threshold refers to the amount of costs that would be deferred during the application development stage described below. It does not refer to the total costs that would be incurred during all three project stages described below.) Please notify the Controller or Director of Corporate and Property Accounting of projects that are less than $500K that will be expensed.

Accounting for Computer Software Guidelines

The costs of software upgrades and enhancements that do not provide additional functionality to the existing software (i.e., modifications to the existing software that would enable the software to perform tasks that it was previously incapable of performing) should be charged to the appropriate functional O&M expense account(s), i.e. expensed as incurred, based on the benefiting organization.

Software that is acquired, internally developed, or modified solely to meet the entity's needs should adhere to the guidance set forth below. In general, software development can be segregated into three stages as follows (also summarized in Exhibit 1):

- Preliminary Project Stage. This stage includes conceptual formulation of software alternatives, evaluation of the alternatives, determination of the existence of needed technology, and final selection of alternatives. Internal and external costs incurred during this stage should be charged as incurred to the appropriate functional O&M expense account(s), based on the benefiting organization, i.e. expensed as incurred.

- Application Development Stage. This stage includes the design of a chosen path, including software configuration and software interface, coding, software installation, and testing, including parallel processing. Certain internal and external costs incurred during this stage should be deferred, including costs to develop or obtain software that allows for access of old data by new systems. Certain applicable overhead and AFUDC costs on the deferrable software costs is also deferred.

  The process of data conversion from old to new systems may include purging or cleansing of existing data, reconciliation or balancing of the old data and the old/new system, creation of new/additional data, and conversion of old data to the new system. Data conversion often occurs during the Application Development Stage; however, data conversion costs, other

ACCOUNTING FOR THE COSTS OF COMPUTER SOFTWARE DEVELOPED OR OBTAINED FOR INTERNAL USE

(Updated as of April 1, 2006)

than the costs to develop or obtain software that allows for access of old data by new systems, should be charged as incurred to the appropriate functional O&M expense account(s), based on the benefiting organization, i.e. expensed as incurred.

- Post-Implementation/Operation Stage. This stage includes training and application maintenance. Internal and external costs incurred during this stage should be charged as incurred to the appropriate functional O&M expense account(s), based on the benefiting organization, i.e. expensed as incurred.

Further, costs of activities typically associated with business process reengineering should be charged as incurred to the appropriate functional O&M expense account(s), based on the benefiting organization, i.e. expensed as incurred. Note that these activities can occur during any stage above. Examples include the following:

- Preparation of a request for proposal
- Current state assessment – The process of documenting the entity's current business process, except as it relates to current software structure. Often referred to as *mapping, developing an "as-is" baseline, flow charting*, and *determining current business process structure.*
- Process reengineering – The effort to reengineer the entity's business process to increase efficiency and effectiveness. This activity is sometimes referred to as *analysis, determining "best-in-class," profit/performance improvement development*, and *developing "should-be" processes.*
- Restructuring the work force – The effort to determine what employee is necessary.

Accounting for Computer Hardware Guidelines:
Any computer hardware costs incurred relative to the development or acquisition of software should be capitalized following existing Company policies and procedures. Computer operating system software which is acquired in connection with new hardware should be capitalized together with the hardware under the basis that the operating system is needed to deem the hardware "used or useful".

ACCOUNTING FOR THE COSTS OF COMPUTER SOFTWARE DEVELOPED OR OBTAINED FOR INTERNAL USE

(Updated as of April 1, 2006)

Exhibit 1

The following table sets forth the accounting for typical components of a software development project based on whether the item should be expensed, deferred, or capitalized. Please note that some of the activities listed below may occur in multiple stages.

	Internal or Third Party		
Steps	**Expensed**	**Deferred**	**Capitalized**
Business process reengineering and information technology transformation (these activities primarily occur, but not limited to, prior to preliminary project stage):			
Preparation of request for proposal (RFP)	X		
Current state assessment (*i.e., mapping, developing an "as-is" baseline, flow charting, determining current business process structure.*)	X		
Process reengineering (*i.e., analysis, determining "best-in-class," profit/ performance improvement development, developing "should-be" processes.)*	X		
Restructuring work force	X		
Preliminary software project stage activities:			
Conceptual formulation of alternatives	X		
Evaluation of alternatives	X		
Determination of existence of needed technology	X		
Final selection of alternatives	X		
Examples of the preliminary project stage include: • Strategic decisions to allocate resources between alternative projects at a given point in time (e.g., should programmers develop a new payroll system or direct their efforts toward correcting existing problems in an operating payroll system?) • Determine the performance requirements (i.e., what the software needs to do) and systems requirements for the project • Invite vendors to perform demonstrations of how their software will fulfill an entity's needs • Explore alternative means of achieving specified performance requirements (e.g., should an entity	X		

ACCOUNTING FOR THE COSTS OF COMPUTER SOFTWARE DEVELOPED OR OBTAINED FOR INTERNAL USE

(Updated as of April 1, 2006)

	Internal or Third Party		
Steps	**Expensed**	**Deferred**	**Capitalized**
make or buy the software? Should the software run on a mainframe or a client server system?) • Determine that the technology needed to achieve performance requirements exists • Select a vendor if an entity chooses to obtain software • Select a consultant to assist in the development or installation of the software			
Application development stage activities:			
Design of chosen path, including software configuration and software interface		X	
Coding		X	
Installation to hardware		X	
Testing, including parallel processing phase		X	
Data conversion costs: a. Costs to develop or obtain software that allows for access of old data by new system		X	
b. Process of converting data from old to new systems (e.g., purging or cleansing of existing data), reconciliation or balancing of the old data and the new data in the new system, creation of new/additional data, and conversion of the old data to the new system.	X		
Training	X		
Post-implementation/ operation stage activities:			
Training	X		
Application maintenance	X		
Ongoing support	X		
Acquisition of fixed assets:			
Purchase of hardware, office furniture, or work stations, including operating system			X
Reconfiguration of work area - architect fees and hard construction costs			X

Exhibit D

GMS Phase 1 Application

Interim Recovery

Note: References to exhibits in this document refer to exhibits included in the accompanying application unless otherwise noted.

INTERIM RECOVERY

The Hawaiian Electric Companies[1] are requesting interim recovery of certain Grid Modernization Strategy ("GMS") Phase 1 ("Phase 1") costs through the Major Project Interim Recovery ("MPIR") adjustment mechanism ("Mechanism"). In particular, the Companies are requesting to recover the Capital ("Capital") and Deferred ("Deferred") costs ("Costs") of Phase 1 (totaling $86.3 million): (i) through the MPIR Mechanism until base rates that reflect the revenue requirements associated with the Capital Costs and Deferred Costs of the project take effect in a future rate case for each respective company; and/or (ii) to the extent not approved for recovery through the MPIR Mechanism, by including the Phase 1 costs in the Renewable Energy Infrastructure Program ("REIP") Surcharge ("Surcharge") until base rates that reflect the revenue requirements associated with the Deferred Costs take effect in a future rate case for each respective company; and/or (iii) a future rate case for each respective company, with amortization of the Deferred Costs commencing when base rates that reflect the Deferred Costs take effect in those respective proceedings.

Pursuant to Section III.B.1.(f) of the MPIR Guidelines, the projects and costs that may be eligible for recovery through the MPIR Mechanism include: "Grid Modernization projects. Projects such as smart meters, inverters, energy storage, and distribution automation to enable demand response." Accordingly, the Companies are requesting to utilize the MPIR Mechanism to recover certain Capitalized (depreciation) and Deferred (amortization) costs of the Project in between rate cases.

The Companies acknowledge that certain portions of the Commission's order establishing the MPIR Guidelines could be interpreted as precluding the recovery of Deferred software costs through the MPIR Mechanism.[2] For example, in discussing deviations from the Joint Proposed REIP Framework ("REIP Framework") that had been previously proposed by the Companies and Consumer Advocate, Paragraph 142 of Order 34514 states:

> [S]pecific references regarding recovery of Deferred costs or expenses were removed. The Guidelines offer one possible means to provide for recovery of revenue for specific project net costs. Deferral of costs or expenses, as may be approved in any specific instance by the commission, remains a separate cost recovery option, which is not changed or replaced by the Guidelines.[3]

The Companies recognize that the removal of "references regarding recovery of Deferred costs" from the Joint Proposed REIP Framework could be read to imply intent by the

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[1] The "Hawaiian Electric Companies" or "Companies" are Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Maui Electric Company, Limited ("Maui Electric") and Hawai'i Electric Light Company, Inc. ("Hawai'i Electric Light").
[2] See Docket No. 2013-0141, *Decoupling Re-examination*, Order No. 34514 ("Order 34514"), issued April 27, 2017.
[3] Id. at 102, para. 142.

Commission to preclude the recovery of Deferred software project costs through the MPIR Mechanism. However, given the Commission's express inclusion of the costs of "Grid Modernization" projects – which generally always involve software implementations (e.g., for meter data management systems) – among the projects that are eligible for MPIR recovery, the Companies interpret Paragraph 142 to mean that, although the MPIR Guidelines provide "one possible means" to recover Deferred software project costs, approval to defer and recover such costs in a general rate case "remains a separate cost recovery option, which is not changed or replaced by the Guidelines." In short, the Companies' overall interpretation of Order 34514 and the MPIR Guidelines is that Deferred software costs for grid modernization projects are not precluded from recovery through the MPIR Mechanism, but, rather, may still be recovered as "[o]ther relevant costs" pursuant to Section III.C.2.b.(iii) of the MPIR Guidelines.

While the Companies believe their interpretation of Paragraph 142 to be reasonable when considered in the overall context of Order 34514, the Companies also acknowledge that reasonable minds could differ with respect to whether part of the intent of that order was to preclude the recovery of Deferred software project costs through the MPIR Mechanism. Therefore, if the Commission is inclined to preclude recovery of the Deferred Project costs through the MPIR Mechanism, then the Companies request approval to recover the Deferred Costs through the REIP Surcharge until base rates that reflect the revenue requirements associated with the Deferred Costs take effect in a future rate case for each respective company, or, if the Commission does not allow recovery through the REIP Surcharge, then in a future rate case for each respective company, with amortization of the Deferred Costs commencing when base rates that reflect the Deferred Costs take effect in those respective proceedings.

I. BACKGROUND

In Order 34514, "utilizing the constructive language and provisions in the Joint Proposed REIP Framework, as appropriately amended,"[4] the Commission established the MPIR Guidelines for the MPIR Mechanism. Specifically, the Commission found that:

> [T]he Joint Proposed REIP Framework includes provisions, agreed to by the HECO Companies and the Consumer Advocate, that can serve as guidelines regarding interim recovery of revenues for major projects placed in service between general rate cases, consistent with the purposes for the development of standards and guidelines identified in the [decoupling] Schedule B Order.[5]

The purpose of the MPIR is to provide a mechanism for recovery of revenues for net costs of approved "Eligible Projects" placed in service between general rate cases that are not provided for by other effective tariffs.[6] "Eligible Projects" are "approved major projects eligible

[4] Id. at 101, para. 139.
[5] Id., para. 138.
[6] See MPIR Guidelines, Section II.A, at 2.

for revenue recovery through the MPIR Mechanism as provided in [the MPIR] Guidelines."[7] As set forth below, Phase 1 qualifies for MPIR recovery.

In Order No. 35026 *Establishing Statement of Issues*, filed November 13, 2017 in Docket No. 2017-0213 (Schofield Generating Station Cost Recovery) the Commission noted:

> Whether or not a project, or an application for interim recovery under the MPIR Guidelines, "meets every standard" or "satisfies all criteria" contained in the Guidelines should not be interpreted either as guaranteeing or as preventing approval of interim cost recovery.[8]

Rather, the Commission will determine on a case by case basis whether it is appropriate, just, and reasonable to exercise its discretion and allow recovery through the MPIR.[9] The Commission further noted that the provisions in the MPIR Guidelines are "guidelines, not to be construed as rules that must be strictly interpreted or deemed dispositive" and further stated that the Commission "may allow considerable latitude in implementing the MPIR Guidelines depending on the circumstances presented in each application."[10]

A. PHASE 1 OF THE GMS QUALIFIES FOR MPIR RECOVERY

1. MPIR Recovery of Phase 1 Costs Will Not be Duplicative

Section II.B.2 of the MPIR Guidelines prohibits duplicative cost recovery and states as follows:

> Notwithstanding any other specific provisions in these Guidelines, the MPIR adjustment mechanism shall not collect or recover revenues for costs or expenses recovered through other effective tariffs or revenue recovery mechanisms. The utility shall have the burden of proof in an application for recovery of revenues through the MPIR adjustment mechanism that recovered revenues should not be duplicative.[11]

The Companies' Application does not seek duplicative cost recovery. The Project's costs are incremental costs that are neither included in Hawai‘i Electric Light's, Hawaiian Electric's, or Maui Electric's base rates from their 2016, 2017, or 2018 test year rate cases, respectively, nor recovered through any recovery mechanism that is currently in effect.

[7] Id., Section I at 1.
[8] See Docket No. 2017-0213, Order No. 35026, issued November 13, 2017, at 7-8.
[9] Id. at 8.
[10] Id. at 8-9 (inconsistency of Application with Guidelines did not prevent consideration of Application).
[11] Id., Section II at 2.

2. Phase 1 is an Eligible MPIR Project

Pursuant to Section III.B.1 of the MPIR Guidelines, projects and costs that may be eligible for recovery through the MPIR Mechanism are major projects subject to review and approval in accordance with the provisions of General Order No. 7 ("G.O. 7"), including but not restricted to:

(a) Infrastructure that is necessary to connect renewable energy projects. Infrastructure projects such as transmission lines, interconnection equipment and substations, which are necessary to bring renewable energy to the system. For example, renewable energy projects, such as wind farms, solar farms, biomass plants and hydroelectric plants, not located in proximity to the electric grid must overcome the additional economic barrier of constructing transmission lines, a switching station and other interconnection equipment. Building infrastructure to these projects will encourage additional renewable generation on the grid;

(b) Projects that make it possible to accept more renewable energy. Projects that can assist in the integration of more renewable energy onto the electrical grid. For example, new firm generation or modifications to firm generation to accept more variable renewable generation or energy storage and pumped hydroelectric storage facilities that allow a utility to accept and accommodate more as-available renewable energy;

(c) Projects that encourage clean energy choices and/or customer control to shift or conserve their energy use. Projects that can encourage renewable choices, facilitate conservation' and efficient energy use, and/or otherwise allow customers to control their own energy use. For example, smart meters would allow customers to monitor their own consumption and use of electricity and allow for future time-based pricing programs. Systems such as automated appliance switching would provide an incentive to customers to allow a utility to mitigate sudden declines in power production inherent in as-available energy;

(d) Approved or Accepted Plans, Initiatives, and Programs. Capital investment projects and programs, including those transformational projects identified within the Companies' ongoing planning and investigative dockets, as such plans may be approved, modified, or accepted by the Commission, and projects consistent with objectives established in investigative dockets;

(e) Utility Scale Generation. Electric utilities may seek recovery of the costs through the MPIR adjustment mechanism for utility scale generation that is renewable generation or a generation project that can assist in the integration of more renewable energy onto the electrical grid;

(f) Grid Modernization projects. Projects such as smart meters, inverters, energy storage, and distribution automation to enable demand response.

Phase 1 qualifies under Sections III.B.1(b), III.B.1(c), III.B.1(d), and III.B.1(f) of the MPIR Guidelines.

In particular, Phase 1 of the Companies' GMS includes investments in advanced meters, a Meter Data Management System ("MDMS"), and a field area network telecommunications network. These three key components are part of a modern grid platform that will support recent Commission decisions and planning initiatives, such as the approved Distributed Energy Resource ("DER") and Demand Response ("DR") programs, as well as the GMS and the Companies' Power Supply Improvement Plan ("PSIP"). Phase 1 is therefore eligible under Sections III.B.1.(d) and (f).

In addition, as discussed in Exhibit B (*Project Justification with Business Case Support*), the proposed projects will make it possible to accept more renewable energy and enable expanded customer participation in DER, DR, and Time-of-Use ("TOU") programs.

The Companies' vision is to use advanced technologies to modernize the existing grid into a platform for enhancing customer value and to provide operational flexibility to integrate more renewables. Beginning with Phase 1, the electric grid will evolve to enable and support the integration and optimal utilization of customer resources made available through existing and new DER and DR programs, as reflected by the renewable generation level projections in the *PSIP Update Report: December 2016* and summarized in the Table 1 below.[12]

[12] See GMS at 3.

December 2016 PSIP Projections for Demand Response and Distributed Energy Resources		
Generation Source	2017-2021	2022-2045
New Distributed Solar Photovoltaic (DG-PV)	326 MW	2,086 MW
New Customer Self-Supply (CSS) Energy Storage	89 MWh	1,057 MWh
New Demand Response Capacity	115 MW	442 MW
New Demand Response Energy Storage	104 MWh	1,608 MWh

Table 1

Moreover, the advanced meters, MDMS, and telecommunications network backbone are being pursued in Phase 1 for a variety of reasons, including the following: (1) the advanced meters and MDMS are needed to enable recently approved DER and DR programs, anticipated future programs like TOU, and other DER programs that progress toward the Commission's vision for a robust DER market; (2) these investments align with building a platform for a proportional, flexible, and scalable approach for grid modernization with discrete and manageable phases; and (3) perhaps most importantly, Phase 1 is the logical first step to support existing energy policies and customer-owned energy resources toward achieving Hawai‘i's Renewable Portfolio Standards goals.

Phase 1 will therefore enable current and future customer-facing programs that facilitate customer choice through expanded customer adoption of DER, integration of community-based solar and energy storage projects, and participation in various advanced energy management services, such as DR, Controlled Customer Grid Supply and TOU rates. This includes through the development of an online energy portal for customers to access and review their electricity usage as part of the MDMS deployment. See Exhibit A (*Working Plan*).

Stated differently, as discussed in Exhibit B, the proposed projects will make it possible to accept more renewable energy and enable expanded customer participation in DER, DR, and TOU programs. Therefore, Phase 1 also qualifies under Sections III.B.(b) and (c) of the MPIR Guidelines.

3. The Phase 1 Application is Compliant with Section III.C.3. Of the MPIR Guidelines

Section III.C.3.(a) through (j) of the MPIR Guidelines establish certain requirements for applications seeking recovery through the MPIR Mechanism. As discussed below, Phase 1 satisfies each of these requirements.

a. Burden of Proof

Section III.C.3.a of the MPIR Guidelines provides:

> With respect to applications seeking approval to utilize the MPIR adjustment mechanism for cost recovery, the electric utility bears the burden of proof that all project costs proposed for MPIR treatment meet the criteria specified herein and are not routine replacements of existing equipment or systems with like kind assets, relocations of existing facilities, restorations of existing facilities, or other kinds of business-as-usual investments.

Meeting customers' needs and achieving Hawai'i's clean energy goals are not possible with the current grid; *the grid we currently have is not the grid we need*. The purpose of Phase 1 is to implement three fundamental platform investments: (1) advanced meters with integrated communications; (2) an MDMS, which is the system of record for advanced metering data and configuration; and (3) an interoperable, scalable telecommunication network to enable the communication path for both the advanced meters and the, future phase, advanced distribution management system's field devices. These three key components are part of a modern grid platform (i.e., the grid the Companies need) that will provide immediate value to customers, and will continue to bring additional value as subsequent phases are deployed. Phase 1 does not involve "routine replacements of existing equipment or systems with like kind assets, relocations of existing facilities, restorations of existing facilities or other kinds of business as usual investments."

b. G.O. 7 Application

Section III.3.b. of the MPIR Guidelines provides:

> Application for recovery of revenues through the MPIR adjustment mechanism shall be made in conjunction with and as part of an application pursuant to General Order No. 7.

The Companies' application for recovery of revenues through the MPIR Mechanism is submitted in conjunction with and as part of the accompanying Application, which seeks General Order No. 7 ("G.O.7") approval.

c. Costs Net of Benefits

Section III.C.3.c. of the MPIR Guidelines provides:

> Costs recovered through the MPIR adjustment mechanism shall be offset by all known and measurable operational net savings and benefits resulting from the Eligible Projects (including accumulated depreciation and accumulated Deferred income tax reserves, reductions in operating and maintenance expenses, related additional revenues, etc.), to the extent such savings or benefits are not passed on to ratepayers through energy cost or other adjustment clause mechanisms, and to the extent that such savings or benefits can reasonably be quantified. Net savings and benefits shall be offset as they are realized to the extent feasible. A business case study shall be submitted with each application

> identifying and quantifying all operational and financial impacts of the Eligible Project and illustrating the cost/benefit tradeoffs that justify proceeding with the project to the extent that such impacts can reasonably be determined.

The Companies are proposing to implement grid modernization in an as-needed, where-needed manner that will maximize value for customers while minimizing rate impacts. This proportional approach seeks to strike a balance between economies of scale from a full deployment and the risk of stranded assets due to obsolescence and/or inability to adopt future technological advancements. Some cost savings may be foregone in the near term compared to an immediate system-wide implementation, due to economies of scale. For example, in contrast to a system-wide approach, which could potentially avoid meter reading costs, under the proposed targeted approach, until advanced meter deployments reach a saturation point for an area, meter readers will still be needed to physically read those meters that have not yet been replaced.

Nevertheless, this targeted approach is intended to enable and assist in realizing the benefits of customer energy options, including customer participation in DR, DER, and TOU programs. Therefore, for each of the Companies, Phase 1 costs will be offset by benefits for customers who will be able to take advantage of programs that are enabled through the implementation of grid modernization technologies.

d. MPIR Eligibility

Section III.C.3.d. of the MPIR Guidelines provides:

> Application for Eligible Projects hereunder shall be made, pursuant to General Order No. 7 procedures. Smaller qualifying Capital projects that are similar in nature or directly related in purpose may be combined or grouped into programs for review in accordance with General Order No. 7 procedures. Applications shall explain each basis for claimed MPIR eligibility, indicating the linkage of the project to any previously submitted planning studies, previously submitted construction budgets and any relevant active Commission dockets. Applications shall also include the information set forth in the following paragraphs (e) through (i).

As discussed above, the Application has been filed pursuant to G.O. 7 procedures; in addition, also as discussed above, and in the Application, Phase 1 supports recent Commission decisions and planning initiatives, including the approved DER and DR programs, as well as the GMS and the Companies' PSIPs. Phase 1 is thus eligible for MPIR recovery for the reasons stated herein and in the Application and other Exhibits thereto.

e. Project Business Case

Section III.C.3. of the MPIR Guidelines provides:

> A detailed business case study shall be included, covering all aspects of the planned investments and activities, indicating all expected costs, benefits, scheduling and all reasonably anticipated operational impacts. The business case shall reasonably document and quantify the cost/benefit characteristics of the investments and activities, indicating each criterion used to evaluate and justify the project, including consideration of expected risks and ratepayer impacts. The business case should also clearly outline how it will advance transformational efforts with appropriate quantifications, to the extent such quantifications can reasonably be determined.

The Companies have provided the detailed business case in Exhibit B. Additional discussion of the planned execution of investments for Grid Modernization is discussed in Exhibit A.

f. ***Project Schedule and Budget***

Section III.C.3.f. of the MPIR Guidelines provides:

> A detailed schedule and budget for each element of the planned investment and activities shall be submitted, quantifying any contingencies, risks, and uncertainties, and indicating planned accounting and ratemaking procedures and expected net customer impacts.

Please refer to the *Risk* and *Schedule/Operational Impacts* section in Exhibit B and to Exhibit C.

g. ***Criteria for Used and Useful Status***

Section III.C.3.g. of the MPIR Guidelines provides:

> Applications must state the specific criteria that are proposed for determination of used and useful status of the project, to ensure that no costs are Deferred or recovered for new assets that are merely commercially available but are not being used to provide service to ratepayers.

The following criteria for the used an useful status of the Project's various components are further discussed in Exhibit C (*Accounting and Ratemaking Treatment*).

- *Advanced Meters + Meter Headend*

The Companies maintain that the meters will be deemed in service (1) upon receipt as meters are pre-Capitalized, and (2) installation costs will be Capitalized upon completion of the meter installation.

Meter Headend components will be deemed in service (1) upon completion of installation for hardware, and (2) after commissioning for the application software.

- *Meter Data Management System*

The MDMS will be deemed in service (1) upon completion of installation for hardware, and (2) after commissioning for application software.

- *Telecommunications Network + Telecommunication Headend*

The telecommunications network will be deemed in service upon completion of installation.

The telecommunications headend will be deemed in service upon completion of installation of the hardware and operating software.

h. <u>Costs Net of Savings</u>

<u>Section III.C.3.h. of the MPIR Guidelines provides:</u>

> Recoverable costs shall be limited to the lesser of actual net incurred project/program costs or Commission-approved amounts, net of savings.

The Companies acknowledge that costs recoverable through the MPIR Mechanism shall be limited to the lesser of the actual net incurred project/program costs or Commission-approved amounts, net of savings. Please see subsection C.3 (Costs Net of Benefits) above, for a discussion of the anticipated costs, net of benefits.

i. <u>Complex Project Treatment</u>

<u>Section III.C.3.i of the MPIR Guidelines provides:</u>

> Complex projects may be eligible for recovery through the MPIR adjustment mechanism when supported by sufficient detailed business case analysis and documentation of reasonably quantifiable expected impacts, costs and benefits resulting from such projects.

As discussed in the Companies' Application and Exhibits, the Project is complex and will affect numerous aspects of the Companies' operations. As noted above, Phase 1 is supported by the detailed business case analysis and documentation set forth in Exhibit B.

j. <u>Procedural Steps</u>

<u>Section III.C.3.j. of the MPIR Guidelines provides:</u>

> Parties to the proceedings on the applications for recovery of costs through the MPIR adjustment mechanism shall endeavor to complete procedural steps to allow for approval of the application within seven months of the date of the application. The Companies acknowledge that the procedural schedule for MPIR for complex projects may take longer than projects that do not affect numerous aspects of the utility's operations, expenses, or earnings.

The Companies are committed to completing the procedural steps in the instant docket as quickly as reasonably practicable. The Companies also acknowledge, however, that as set forth in Section III.C.3.j., the procedural schedule for applications for recovery of costs through the MPIR for complex projects may take longer than projects that do not affect numerous aspects of the utilities' operations. In particular, as described in Exhibit A, the Companies have assumed a 12-month duration for the procedural schedule. Notwithstanding this assumption, consistent with this section, the Companies are amenable to working with the Consumer Advocate to develop a procedural schedule for this docket that enables the procedural steps to be completed within seven months of this filing, to the extent practicable.

B. <u>DURATION OF MPIR MECHANISM FOR GMS PROJECT</u>

For Phase 1, the Capital and Deferred Costs requested to be recovered through the MPIR Mechanism, totaling $86.3 million, are planned to be placed into service at various points during the 2019-2023 implementation period. Table 2 and Table 3 below, depict the proposed timing of Capital and Deferred costs, by component, as of the year they are placed into service. Table 4 is an illustrative table correlating these plant additions, for the associated components of Phase 1, with the proposed MPIR Mechanism and rate case recovery schedule for each Company.

Company	Account Group	2019	2020	2021	2022	2023
Hawaiian Electric	Capital	[redacted]				
Hawaiian Electric	Deferred					
Hawai'i Electric Light	Capital					
Hawai'i Electric Light	Deferred					
Maui Electric	Capital					
Maui Electric	Deferred					

Table 2

Company	Project/Program	2019	2020	2021	2022	2023	Useful Life
Hawaiian Electric	Advanced Meters (Capital)	[redacted]					30
Hawaiian Electric	Meter Headend Hardware (Capital)	[redacted]					5
Hawaiian Electric	Meter Headend (Deferred)	[redacted]					12
Hawaiian Electric	MDMS (Capital)	[redacted]					5
Hawaiian Electric	MDMS (Deferred)	[redacted]					12
Hawaiian Electric	Telecommunication Headend (Capital)	[redacted]					5
Hawaiian Electric	Telecommunication Mesh Network (Capital)	[redacted]					15
		[redacted]					
Hawai'i Electric Light	Advanced Meters (Capital)	[redacted]					30
Hawai'i Electric Light	Meter Headend (Deferred)	[redacted]					12
Hawai'i Electric Light	MDMS (Deferred)	[redacted]					12
Hawai'i Electric Light	Telecommunication Mesh Network (Capital)	[redacted]					15
		[redacted]					
Maui Electric	Advanced Meters (Capital)	[redacted]					30
Maui Electric	Meter Headend (Deferred)	[redacted]					12
Maui Electric	MDMS (Deferred)	[redacted]					12
Maui Electric	Telecommunication Mesh Network (Capital)	[redacted]					15

Table 3

Year	HECO	HELCO	MECO
2019	MPIR	Rate Case	MPIR
2020	Rate Case	MPIR	MPIR
2021	MPIR	MPIR	Rate Case
2022	MPIR	Rate Case	MPIR
2023	Rate Case	MPIR	MPIR

Table 4

In Order No. 35026 *Establishing Statement of Issues*, issued November 13, 2018 in Docket No. 2017-0213 (Schofield Generating Station Cost Recovery) the Commission noted:

> [A]s with any substantial new regulatory framework, the commission recognizes that there may be details regarding the effective and efficient implementation of the MPIR Guidelines that are not specifically addressed or resolved in the Guidelines or the commission's prior orders. As the Application in this proceeding is one of the first instances of implementation of the MPIR Guidelines, the scope of issues in this proceeding should also include examination and resolution of details not explicitly contemplated or addressed in the Guidelines, but necessitated by the circumstances.[13]

It should be noted the proposal to begin including the GMS Phase 1 costs in the Companies' respective base rates in future rate cases is less specific than Hawaiian Electric's proposals in Docket Nos. 2018-0102 (Contingency & Regulating Reserve BESS) and 2018-0103 (West Loch BESS) to continue MPIR recovery until base rates that reflect the unrecovered costs of those projects take effect in Hawaiian Electric's 2023 test year rate case. As explained in those dockets, Hawaiian Electric's proposed BESS projects are proposed to be placed in service in 2020. Under the average rate base methodology utilized in rate cases, if Hawaiian Electric were to seek cost recovery for those projects through its next scheduled rate case (i.e., the Hawaiian Electric 2020 test year rate case), then only half of the Project costs would be included in the 2020 test year revenue requirements. Therefore, in the interest of simplicity, Hawaiian Electric proposed that the costs of those projects remain in the MPIR Mechanism until its 2023 rate case.

The GMS Phase 1 presents cost recovery challenges not presented in connection with Hawaiian Electric's recent BESS applications. For example, the BESS projects each have a single, one-time in-service date. In contrast, the various components of the GMS Phase 1 are proposed to be placed in service over the period between 2019 and 2023. Moreover, whereas the BESS applications involve only a single utility (i.e., Hawaiian Electric), the GMS Phase 1 involves all three of the Hawaiian Electric Companies, which are currently required to follow a staggered triennial rate case cycle. The combination of rolling in-service dates and the Companies' staggered rate cases would make it difficult if not impossible to take advantage of the simplified approach that Hawaiian Electric has proposed for its BESS projects. The MPIR Mechanism would address cost recovery when the GMS Phase 1 costs are not yet incorporated in base rates. The Companies are proposing to maintain a degree of flexibility with respect to the timing of the MPIR Mechanism. The Companies intend to work with the Consumer Advocate on a going-forward basis to develop the mechanics of a mutually-acceptable cost recovery proposal that is transparent, fair and efficient.

[13] See GMS at 10.

Exhibit I (*Bill Impact*) includes the revenue requirements and customer bill impact calculations for the Project. These high-level revenue requirement and bill impact calculations include simplifying assumptions which are discussed further in Exhibit I. In the actual MPIR filing, the revenue requirements will be based on actual costs incurred and detailed classification of the costs in the depreciation and tax calculations. An illustration of the MPIR calculation is provided in Exhibit J (*Hawaiian Electric Companies' Decoupling Calculation Workbook*).

The various revenue requirement components are addressed below:

a. Depreciation assumptions (MPIR Guidelines Section III.C.2.ii) – The MPIR revenue requirement will be based on the depreciation rates in place at the time of filing.

b. Rate of return assumption (MPIR Guidelines Section III.C.2.1) – Eligible costs will include the allowed rate of return or other form of return mechanism (set in the last rate case of the utility where the Project is located) on the investment from the in-service date of the Project. (See Exhibit I). Cost of Capital will be based on the weights and rates in effect for rates at the time of the MPIR filing.

c. Show net of tax annual undepreciated investment in allowed Eligible Projects (essentially a rate base calculation with Capital investment, accumulated depreciation, accumulated Deferred income taxes, and unamortized State investment tax credit) (MPIR Guidelines Sections III.C.2.i and III.C.3.c) (See Exhibit I). Depreciation and taxes will be based on the rates and regulations in place at the time of filing (when the Project goes into service and in January in the years following).

II. RENEWABLE ENERGY INFRASTRUCTURE PROGRAM SURCHARGE RECOVERY

If the Commission is not inclined to allow the Companies to recover the Deferred Costs through the MPIR Mechanism, then the Companies request approval to recover the Deferred Costs through the REIP Surcharge until base rates that reflect the revenue requirements associated with the Deferred Costs take effect in a future rate case for each respective company.[14]

A. INTRODUCTION

On December 30, 2009, the Commission issued its *Decision and Order* in Docket No. 2007-0416, approving the Companies' proposed REIP, including the REIP Surcharge, subject to certain conditions.[15] The Companies' proposed REIP was presented in their *Reply Statement of Position*, filed on September 17, 2008 in Docket No. 2007-0416, which codified specifics of the

[14] If the Commission is not inclined to allow recovery of the Deferred Costs through either the MPIR Mechanism or REIP Surcharge, then the Companies propose to recover the Deferred Costs through a future rate case for each respective company, with amortization of the Deferred Costs commencing when base rates that reflect the Deferred Costs take effect in those respective proceedings.

[15] In Order 34514, issued April 27, 2017 in Docket 2013-0141, at 101, the Commission reaffirmed that the "REIP remains as approved in Decision and Order dated December 30, 2009 in the REIP Docket."

proposal in Exhibit B – *HECO Companies' Proposed Renewable Energy Infrastructure Program Framework*. The purpose of the REIP is to

> (a) encourage development of and investment in renewable energy infrastructure projects in order to facilitate third-party development of renewable energy resources and maintain current renewable energy resources, and (b) to enhance energy choices for customers by providing a means for the Companies to recover their investment in Renewable Energy Infrastructure Projects in a timely fashion.[16]

B. RECOVERY OF PHASE 1 DEFERRED COSTS THROUGH THE REIP SURCHARGE IS APPROPRIATE

Under the REIP Framework, the types of projects eligible for REIP Surcharge recovery include infrastructure that is necessary to connect renewable energy projects, projects that make it possible to accept more renewable energy, and projects that encourage renewable choices and/or customer control to shift or conserve the customer's energy use.[17] Here, the Companies maintain that Phase 1 is eligible under the following REIP categories:

- *Projects that make it possible to accept more renewable energy; and*
- *Projects that encourage renewable choices and/or customer control to shift or conserve the customer's energy use*.

These REIP eligibility categories are equivalent to the eligibility categories set forth in Sections III.B.1(b) and III.B.1(c) of the MPIR Guidelines. For similar reasons that Phase 1 is an eligible project under the MPIR Guidelines as discussed above, the Companies believe that it is also an eligible project under the REIP Framework.

In addition, Section II.B.1 of the REIP Framework provides that electric utilities may recover the "Capital Costs, Deferred costs relating to software development and licenses, and/or other relevant costs approved by the Commission." In particular, Section III.B.3.b of the REIP Surcharge defines eligible costs to include:

> (i) allowed rate of return or other form of return mechanism (set in the last rate case of the utility where the Project is located) on the investment from the in-service date of the Project;
>
> (ii) depreciation (at a rate and methodology to be set forth in the Project's application) to begin the month after the in-service date of the Project;

[16] See REIP Framework at Section III.A.1.
[17] See REIP Framework at Section III.B.1.a.

(iii) AFUDC, applicable taxes, and other Capital and Deferred expense related charges; and

(iv) other relevant costs as approved by the Commission in an request for approval to include the costs of the Project in the REIP Surcharge.[18]

Accordingly, the Companies maintain that the Phase 1 Deferred Costs are eligible for recovery through the REIP Surcharge.

[18] See REIP Framework at III.B.3.b.

Exhibit E

GMS Phase 1 Application

Request for Proposals

REQUEST FOR PROPOSALS

This Application ("Phase 1") serves as the initial groundwork to build the platform that is needed to create the foundation for a modernized grid that is consistent with the Hawai'i Public Utilities Commission's ("Commission") principles.[1] Accordingly, the goal of Phase 1 is to procure and deploy three fundamental platform investments:

- Advanced meters with integrated communications, which record electricity demand, usage, and power characteristics in configurable intervals as well as send notifications for anomalous conditions to provide the Hawaiian Electric Companies[2] with more insight into the distribution grid and support the Companies' growing portfolio of customer energy options;[3]

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

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

I. RFP PROCESS

The Companies leveraged the smart metering and MDMS Request for Proposals ("RFP") from the Smart Grid Foundation Project ("SGFP") as a starting point for the GMS RFPs to identify the baseline requirements anticipated for Phase 1. Additionally, the Companies utilized a telecommunication specification from the Electric Power Research Institute ("EPRI") *Telecommunications Initiative*[4] to develop the field area network ("FAN") specification for the Telecommunications System Request for Proposal. Recognizing that time is of the essence to support the recently approved DER and DR programs, this approach saved the Companies and customers the cost, time, and effort associated with starting the procurement processes from scratch. Furthermore, the RFP process was initiated in 2017 after the filing of the final GMS and

[1] See Docket No. 2017-0226, *Modernizing Hawai'i's Grid For Our Customers*, filed August 29, 2017, Section D, (Guiding Principles), at 51-52.
[2] Hawaiian Electric Company, Inc., Hawai'i Electric Light Company, Inc., and Maui Electric Company, Limited, are collectively referred to as the "Hawaiian Electric Companies" or the "Companies."
[3] The term "customer energy options" as utilized in this Application is inclusive of existing and new tariffs and/or programs including Demand Response ("DR") Portfolios (including Time-of-Use ("TOU") and future dynamic pricing) and DER programs. All of these options would be inclusive of any customer-sited resources, including but not limited to photovoltaics ("PV"), distributed storage, and electric vehicles ("EVs").
[4] EPRI, *Information, Communication, and Cyber Security (ICCS) Roadmap* (Jan. 2017), available at https://www.epri.com/#/pages/product/3002009115/; and EPRI, *2017 Annual Review and Looking Ahead to 2018: Telecommunication Initiative (Future Project Set 161G)*, available at https://www.epri.com/#/pages/product/3002012344/ (available for purchase, free for EPRI members).

prior to the receipt of D&O 35268 in February 2018, which directed the Companies to proceed with implementing the GMS.

The SGFP smart metering and MDMS RFPs were extensively reviewed both by Hawaiian Electric and external resources, and were updated to align with the GMS vision. This approach leveraged the significant effort that was invested in the SGFP procurement process. Utilizing the EPRI Telecommunication Initiative as a starting point, the Companies refined the specification to align with the GMS vision for a multi-purpose communications platform that supports both advanced meters and other distribution field devices.[5] This approach ensures that the specification being utilized by the Companies is not unique but is the result of collaboration with other utilities and an articulation of industry need to potential suppliers. More importantly, tailoring the telecommunications specification to Hawai‘i helps to mitigate Commission concerns that the telecommunications system will not meet the future needs of the Companies' grid and customers.

The metering and telecommunications RFPs outlined in this exhibit were released to vendors in December 2017, with the MDMS RFP following closely in early January 2018. The resulting vendor proposals help to provide the basis for the budget and cost considerations detailed in the accompanying Application. The actual vendor selection for each solution will be conducted after the Phase 1 Application is filed and in parallel with the regulatory approval process. Prior completion of the proposal evaluation and award would likely delay this application by up to six months as the Companies proceed through vendor interviews, demonstrations, testing, and contract negotiations, as needed. Therefore, submission of the accompanying Application after receiving the proposal pricing but prior to vendor selection is likely to accelerate the implementation of these solutions by an estimated six months.

All of the RFPs were developed and evaluated in context with one another and the Companies' broader initiatives, including support of the recently approved DER programs and enterprise-level initiatives. The Companies issued three separate RFPs (advanced meters, MDMS, telecommunications) corresponding to each major component of the Phase 1 GMS implementation. Although there are some vendors who are able to provide solutions to all three RFPs, the Companies did not mandate a portfolio solution; however, the Companies also did not preclude vendors from participating in all three RFPs. Because these technologies ultimately provide the foundation for the platform as articulated in the GMS, the procurement of each technology was closely coordinated. The evaluation of the RFPs includes assessment to ensure the solutions proposed in each RFP are compatible with each other and consistent with the GMS to ensure that the technology is scalable and compatible in the future to minimize risks of stranded investments. Implementation risk and cost considerations are also being taken into account for each potential combination of vendor solutions.

Evaluation methodologies are consistent across the RFPs. As shown in Figure 1, below, outlines the general procurement process. Shortly after the proposals were submitted by vendors, the Companies held interviews with the vendors for each RFP to clarify all aspects of

[5] The GMS has identified potential field devices that include remote intelligent switches, remote fault indicators, secondary var controllers, and line sensors.

the vendor response. From there, the proposals were evaluated against a predetermined evaluation methodology, and a selection of the top vendors was made.[6] The Companies are currently in the down-selection, vendor demonstration,[7] and testing portion of the procurement process as of the filing of this Application. As shown in Figure 1, the Companies will actively test the metering and telecommunications solutions in the coming months in an effort to select a vendor for each RFP. To the degree reasonably possible, interoperability of the different vendors and technologies will be verified through bench and/or field testing such that any unexpected issues or challenges are identified prior to final award. In addition to the evaluation criteria identified in this exhibit, interoperability and compatibility across the three technologies will be carefully evaluated leading up to final award for all three RFPs. The Companies' goal is to complete vetting, testing, selection and contract negotiations prior to Commission approval of the Phase 1 Application; meaning that upon the issuance of a favorable D&O, procurement and implementation can begin immediately.

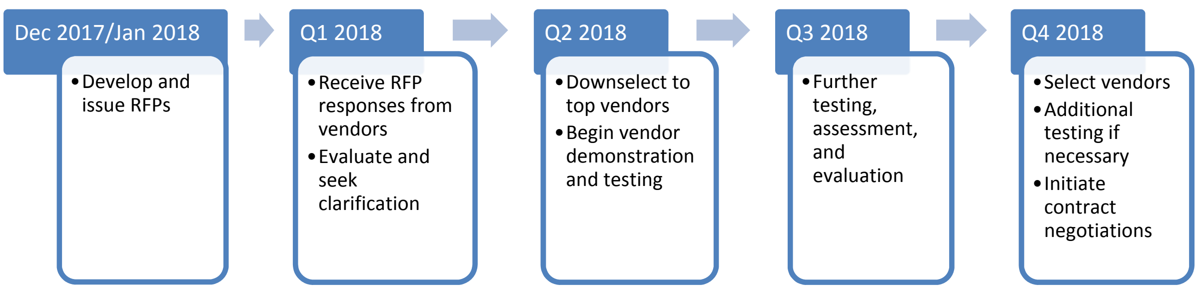

Figure 1

During each portion of the procurement process, significant due diligence has been and will continue to be done in an effort to minimize risk and ensure that the vendor solution aligns with the Companies' vision and anticipated needs. The Companies will weigh all of the information gathered through the vendor responses, demonstrations, and testing in selecting a final vendor for each of the technologies.

II. MECHANICS OF PROPOSAL EVALUATION

At the core of the proposal evaluation for the GMS Phase 1 technologies is the technical solution. The vendors were asked to self-select compliance for each technical requirement in the RFPs within one of six compliance categories (listed below), and all were provided an opportunity to comment on their solution relative to the requirement. Each requirement was designated as ideal, core, or mandatory, and the evaluation methodology considered these designations in assessing the overall vendor proposal. The six compliance categories were as follows:

[6] As discussed in the MDMS section of this exhibit, the MDMS RFP was only issued to the top three vendors from the SGFP solicitation, which effectively functioned as the down-selection.
[7] MDMS vendor demonstrations were completed in May 2018.

1. System as proposed meets standard
2. System will meet standard in scheduled upcoming release
3. System can meet standard using third party products
4. System can meet standard with customization
5. System as proposed does not meet standard
6. Other

The vendors' self-selected scores, comments, and responses to clarification questions were factored into the technical evaluation. Furthermore, the procurement team sought input on vendor solutions and product specifications in an effort to consider not just tri-Company alignment but also cross-organization[8] input.

In addition to technical requirement adherence, each RFP evaluation included weighting for RFP compliance, customer support, cost, and commercial risk. The commercial risk factors capture alignment with the GMS vision, compatibility with current and future systems, alignment with the Companies' architectural approach to grid modernization, the schedule of implementation and product availability, product maturity, implementation and systems integration support from the vendor, and training support to ensure that the Companies' transition to operational practices is smooth and that the technologies procured are leveraged to their highest potential.

As the Companies move forward with vendor demonstrations and testing, information gathered will supplement the existing framework for proposal evaluation such that the final vendor selection will be educated by as much information as possible.

III. ADVANCED METERING RFP

As described in the GMS, advanced metering has evolved to provide improved grid-sensing capability. As a result, many of the prior advanced meter requirements were updated from the SGFP procurement language, and others were added to provide specifications for an advanced metering solution that supports the vision articulated in the GMS. The solicitation also included requests for wired communication options such as power line carrier, which could provide a viable communication solution in rural areas as well as for customers who prefer not to have wireless communications.

The proposal evaluation to date is split between technical and nontechnical requirements, as shown in Table 1 below:

[8] Input from the System Operations, Engineering, Planning, Grid Technologies, Technical Services, Test & Substation, Information Technology Services, Information Assurance, Legal, and Purchasing departments/business units has been valuable in assessing the technologies under consideration.

Evaluation Criteria (listed alphabetically)
Adherence to RFP Instructions and Standard Contract Terms & Conditions
Commercial Risk
Meter Non-Technical Requirements
Meter Technical Requirements
Price

Table 1

As of the filing of this Application, the advanced meter selection team has evaluated and scored each bidder proposal and the results have been reviewed and vetted by the selection and project teams. A "best and final offer" solicitation will be provided to each of the meter vendors with additional questions and clarifications. The result of the best and final offer solicitation will result in a down-selection of candidate vendors. Metering solutions from the down-selected vendors will proceed to laboratory and potential field testing prior to final vendor selection.

IV. METER DATA MANAGEMENT SYSTEM RFP

Deploying advanced meters to support DR and DER programs necessitates the procurement and installation of an MDMS to be the system of record for advanced metering data, including both measurements and meter configuration information.

After reviewing the RFP and vendor responses associated with the SGFP procurement, the functionality of the envisioned MDMS for GMS has not changed significantly. However, the technology and functionality of vendor solutions in the marketplace has matured and stabilized. As a result, the Companies reissued the SGFP MDMS RFP to the top three down-selected vendors identified for the SGFP in order to leverage the significant level of due diligence associated with MDMS assessment for that project. This approach saved customers the cost, time, money and effort associated with starting the MDMS procurement process over. While the fundamental functional MDMS requirements did not change, updates were made to some of the requirements in order to clarify MDMS specifications to support the GMS. Security requirements were also updated. In addition, each updated technical requirement was identified to enable the vendors to utilize their prior proposals as a starting point rather than start from scratch. The reissue of this RFP solicited a detailed response from bidders to include updated pricing and service descriptions.

The proposal evaluation to date is split between technical and nontechnical requirements as well as the vendor demonstrations, as shown in Table below:

Evaluation Criteria (listed alphabetically)
Adherence to RFP Instructions and Standard Contract Terms & Conditions
Commercial Risk
Customer Support
MDMS Non-Technical Requirements
MDMS Technical Requirements
MDMS Vendor Demonstrations
Price

Table 2

As of the filing of this Application, the MDMS selection team has evaluated and scored each bidder proposal and the results have been reviewed and vetted by the selection team, project team, and other key stakeholders from across the Companies. The MDMS bidders provided a demonstration of their products to the MDMS selection team in early May 2018, responding to prescribed scenarios and questions to address during the demonstration. This process will enable the MDMS selection team to compare each vendor solution equally and to evaluate the key functionalities of the MDMS solution that will be key to real-world implementation. One or all bidders may be requested to provide a best and final offer solicitation after demonstrations have been reviewed. The decision to solicit “final offers” from vendors will be closely coordinated with the schedule for telecommunications and metering such that the components of this Application are technically compatible from the meter through to the Companies’ back office.

V. TELECOMMUNICATIONS RFP

The Telecommunications RFP seeks a solution(s) proposal and costing for an overarching and cost-effective telecommunications network that will support multiple required and anticipated applications. These RFP documents included requirements that provision several layers of transport and may require a multi-step and/or a multi-product approach utilizing emerging technology. As noted above, a telecommunications network is a foundational platform component required to support safe, secure, reliable, and efficient operation of a modern electric system.

The goal of the Telecommunications RFP is to acquire concise telecommunications network proposals based upon both industry- and Company-prescribed specifications and requirements, including estimated pricing, which will ultimately enable the Companies to select a telecommunications network to expand and evolve to support the proportional and prioritized deployment of GMS solutions over time at the lowest reasonable cost.

As of the filing of the Phase 1 Application, the Companies have conducted an initial down-selection of candidate vendors based on proposals, interviews and follow-up questions. The proposals that were not selected during the down-selection process did not sufficiently meet the technical and operational standards as stated in the technical evaluation matrix and/or were not satisfactorily aligned with the GMS, as outlined in the Telecommunications RFP. The Companies are working to schedule additional meetings with the down-selected vendors and anticipate conducting laboratory and field testing prior to selecting a final telecommunications option to validate technical requirements and functionality. The evaluation team will work alongside the vendors during testing in order to better understand and evaluate the proposed solutions, which will ultimately result in the selection of a final vendor solution. Bidders may be asked to revise equipment pricing, architecture, and deployment strategies based on deployment plan updates. The budgetary estimate included with this Application leverages the proportional functionality of vendor solutions.

The proposal evaluation to date is split between technical and nontechnical requirements, as shown in below.

Evaluation Criteria (listed alphabetically)
Adherence to RFP Instructions and Standard Contract Terms & Conditions
Commercial Risk
Customer Support
Price
Telecom Non-Technical Requirements
Telecom Technical Requirements

Table 3

VI. CONCLUSION

The Companies' RFP process leveraged existing work in an attempt to utilize industry best practices and streamline the procurement to benefit customers both with a more timely procurement and a less costly development cycle. The Companies' decision to submit this Application in advance of the final vendor selection (such that the Commission can consider the Application concurrent to testing) is anticipated to expedite the deployment of these foundational grid modernization technologies by roughly six months. Although final vendor selection is still pending, the Companies are comfortable with the level of technical understanding that informed the budgetary allotment included with this Application.

Exhibit F

GMS Phase 1 Application

Stakeholder Engagement and Customer Safeguards

Note: References to exhibits in this document refer to exhibits included in the accompanying application unless otherwise noted.

STAKEHOLDER ENGAGEMENT AND CUSTOMER SAFEGUARDS

Customer and stakeholder interests were at the core of the development of the Hawaiian Electric Companies'[1] Grid Modernization Strategy ("GMS") filing. In Decision and Order No. 35268, the Hawaiʻi Public Utilities Commission ("Commission") acknowledged the Companies' efforts to improve the GMS in response to stakeholder comments and stated an expectation that the Companies "continue this best practice as they develop their application(s) to implement the Strategy."[2] The Companies have continued to seek input and feedback on grid modernization since the GMS filing, including through efforts in the Integrated Grid Planning development and as part of the Phase 1 ("Phase 1") implementation of the GMS. Additionally, the safety, privacy and security of customer information and concern with potential health risks associated with radiofrequency ("RF") exposure were thoroughly vetted to address ongoing customer concerns and potential health impacts presented by modernizing the electric grid. The Companies will continue to seek stakeholder input and customer feedback on their GMS and other grid modernization plans as they progress through the different phases of deployment and implementation. This stakeholder and customer engagement will influence the technologies considered, proposed, and selected as the Companies work toward achieving the State's Renewable Portfolio Standards ("RPS") goals.

I. STAKEHOLDER ENGAGEMENT AND FEEDBACK

In Q1 and Q2 2018, the Companies met with various stakeholders, including Commission staff, the Consumer Advocate staff, the County of Hawaiʻi, the County of Maui, the Ulupono Initiative, and the Department of Business, Economic Development, and Tourism . These stakeholder meetings reinforced public comments received in Docket No. 2017-0226, as well as the stakeholder outreach conducted in the development of the GMS. During these discussions, the stakeholders appeared to be in alignment with the Companies' long-term vision and recognized that investment is needed now to execute upon that vision.

Universally, these meetings found stakeholder consensus around the following three themes:

- There is no question about the short-term plan: investment is needed in a platform that supports both customers and grid operations as the Companies and the communities they serve move toward a shared Power Supply Improvement Plan energy future that involves utilizing distributed resources from customer energy options to complement grid scale resources.

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[1] Hawaiian Electric Company, Inc., Hawaiʻi Electric Light Company, Inc., and Maui Electric Company, Limited, are collectively referred to as the "Hawaiian Electric Companies" or the "Companies."
[2] See Docket No. 2017-0226 ("GMS Docket"), Decision and Order No. 35268, issued February 7, 2018, at 23.

- Grid modernization is needed to provide customer benefits within a reasonable cost. Each of the stakeholders agreed that investment is needed, although opinions differed on cost allocation and quantification of benefits for those who do not participate in customer energy options; including the appropriate cost allocation for customers who opt-in versus those who do not.

- Timely, appropriate, and actionable data sharing and data presentment is important for both grid operators and customers. Multiple stakeholders underscored that timely data is important to customers looking to manage their energy usage in real-time. The Companies note that other jurisdictions have made load profile data available on a nightly basis, but the Companies are exploring opportunities to provide data to customers and their representatives on a more frequent basis, particularly during demand response events or to facilitate time-of-use and future dynamic pricing programs.

The GMS approach is a customizable, modular, and scalable solution that ensures the right technology in the right place at the right time. However, for stakeholders, the phased investment approach means a level of uncertainty regarding when and where GMS solutions will be available. Concern remains that the per-customer cost for deployment via the proposed opt-in approach as part of Phase 1 is more expensive when compared with full deployment, where economies of scale can be realized. However, these concerns are balanced by the progression of grid modernization to achieve functionality when and where it is needed. Additionally, the proportional approach seeks to reduce the risk of stranded investments that may be associated with a full deployment plan. Further, a full deployment approach could result in functionality utilized by only a small number of customers that crowd out future technological innovations. Consistent with Commission direction, the Companies will remain nimble and adjust the grid modernization planning process and investments with inputs from the proposed Integrated Grid Planning ("IGP"); customer adoption of energy options such as Distributed Energy Resources ("DER"), Demand Response ("DR"), and Time-of-Use ("TOU") programs; availability of new and emerging technologies; and input from both stakeholders and customers. This proportional meter deployment approach will gradually provide meters to an increasing population of customers such that completing a system-wide deployment may be cost-effective in the future

As part of their existing customer education and outreach activities, the Companies will continue to provide opportunities for customers and stakeholders to engage with the Companies prior to, during, and throughout the development and implementation of their GMS-related application(s). Such engagement opportunities may be comprised of continuing to track and respond to customer inquiries relating to health concerns from advanced meters, hosting public workshops and/or conferences to engage with industry experts and community leaders on what grid modernization means for Hawaiʻi, and utilizing the lessons learned from previous and future project implementations to ensure that both customers and stakeholders have a voice in the project development process. The Companies further envision the IGP process will include conscientious customer education and outreach activities related to grid modernization.

II. CYBERSECURITY AND DATA PRIVACY

Access to data is a key part of enabling customer choice and control. As part of Phase 1 of the GMS, the Companies are proposing an online customer energy portal, which will be integrated with the Meter Data Management System ("MDMS") utilizing the Green Button[3] functionality for customers and customer-authorized third parties to access the advanced meter data. However, while these new technologies provide customers with valuable new capabilities, any new technology has the potential to expose customers to risks related to privacy and confidentiality of associated customer data. While the Companies plan to explore system-level data sharing through the IGP process, policies are also needed regarding third-party access to customer-specific advanced metering data.

The Companies intend to address the functional and technical requirements that will enable data sharing through the procurement and implementation of equipment and systems through grid modernization, inclusive of laying out specific requirements of vendors who supply the equipment or software that will be feeding and aggregating the data collected. However, questions regarding third-party access to customers' data, including their personally identifiable information, need to be handled fairly and in a responsible manner. The Companies have started to research this topic to address it with the Commission separately.

As part of Phase 1, the Companies have specifically included requirements for the security of the customer energy usage information that will be collected through the advanced meters and MDMS. The requirements necessary to comply with the Companies' comprehensive cybersecurity measures were included as part of the various Request for Proposals ("RFPs") issued for the MDMS and Telecommunications Network systems (see Exhibit E – *Request for Proposals*). These systems will continue to prioritize customer data security with flexibility to evolve as the Companies' grid modernization processes continue to be implemented. Further discussion of the Companies' cybersecurity policies and cybersecurity issues related to Phase 1 can be found in Attachment 1 to this Exhibit.

III. HEALTH AND SAFETY

As stated in the GMS filed with the Commission in August 2017, the Companies' proposed "opt-in" strategy for advanced meters means a much smaller scale of these devices in the field but also introduces the advanced meter as the new standard meter going forward to serve new customers and replace old meters. Over time, this approach will result in all customers being equipped with an advanced meter. In addition to providing customers with access to customer energy options,[4] deploying advanced meters will provide customers with a

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[3] See U.S. Department of Energy, *Green Button Data*, available at https://www.energy.gov/data/green-button and http://www.greenbuttondata.org/.

[4] The term "customer energy options" as utilized in this Application is inclusive of existing and new tariffs and/or programs including DR Portfolios (including TOU and future dynamic pricing) and DER programs. All of these

more safe, reliable and resilient electric grid. Further, Phase 1, which will lay the foundation for the proposed implementation of the Advanced Distribution Management System in Phase 2, can actually help to improve public safety. For example, advanced meters can identify broken electric-neutral connections between the customer and the distribution transformer. The modern grid systems (i.e., Phase 1 and Phase 2 of the GMS implementation) will work in concert to not only keep the Companies' customers powered but also safe by combining more distribution measurement and controls to reduce the number of customer outages and to more quickly de-energize or isolate downed power lines.

A. RF Technology Background

RF waves are much like "radio waves" that have been used for over a century in technologies such as AM/FM/CB radios, VHF/UHF/digital television broadcasting, emergency dispatch services, walkie-talkies, and cellular and wireless devices. RF became widely used in radio devices in the early 1900s, and then in television transmitting stations which proliferated in the 1950s. More recent uses of RF signals include cellular phones, Wi-Fi routers, global positioning system ("GPS") location mapping and satellite radio. In-home sources of RF emissions include baby monitors, microwave ovens, cordless phones, Bluetooth devices and remote-controlled toys. Advanced meters are modern electric meters that utilize low-frequency RF signals to send information to the electricity utility. This two-way data sharing enables capabilities such as wireless meter readings, collection of usage data for customers to better manage their energy use, and automated outage detection that allows for quicker restoration times.

B. Safety of RF Exposure

Myths or misleading claims about advanced meters have caused some concerns about the safety of RF. To address such concerns, scientific study from credible third-party health and research organizations has been conducted and there has been no indication in population health statistics that exposure to radio wave technology has caused increases in the incidence of any disease.

The use of RF technologies is regulated by the Federal Communications Commission ("FCC"), which sets Maximum Permissible Exposure ("MPE") limits on RF exposure levels for the general population. The FCC has developed science-based safety guidelines for RF exposure based upon guidance and recommendations from the U.S. National Council on Radiation Protection and Measurements, the American National Standards Institute ("ANSI"), and the Institute of Electrical and Electronics Engineers ("IEEE"). The FCC also licenses most RF telecommunications services, facilities and devices (including advanced meters).

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options would be inclusive of any customer-sited resources, including but not limited to photovoltaic ("PV"), distributed storage, and electric vehicle ("EV").

The MPE limit for advanced meters is 600 micro-Watts ("µW") per square centimeter ("cm^2"). For an advanced meter in active transmission mode, RF exposure levels at three feet away remain well below (typically $1/300^{th}$) the FCC's MPE limits for RF sources of all types.[5] In other words, the RF from a customer's contact with an advanced meter is exponentially less than other common household devices. In fact, a 2014 testing program on Maui reported RF levels near smart meters (less than a foot away) that were even lower, namely $1/100{,}000^{th}$ (0.001%) to $1/7{,}000^{th}$ (0.014%) of the FCC allowable public-exposure guideline.[6] Moreover, a May 2015 assessment of the RF levels from the Companies' smart meters currently installed on O'ahu reported that the greatest measured RF field at one foot from the meters represented $1/7{,}500^{th}$ (0.013%) of the FCC allowable limit for public human exposure.[7]

Figure 1 below illustrates that, among devices that use RF, advanced meters emit among the lowest RF energy levels.[8] This is represented in peak power levels, with the impact determined by peak (or average) levels multiplied by the duration of exposure. Since advanced meters broadcast for a limited period of time, their total emitted RF energy levels are extremely low.

[5] For advanced meter RF, the MPE limit is 600 microWatts per sq. cm. (600 $\mu W/cm^2$ = 0.6 mW/cm^2 = 6 W/m^2). From Figure 1, "2 $\mu W/cm^2$" divided by "600 $\mu W/cm^2$" equals 1/300.

[6] See Cascadia PM, LLC, *Report of Results of Smart Meter RF Testing – Maui* prepared for the Hawaii Natural Energy Institute (April 15, 2014), available at http://www.mauismartgrid.com/smart-meter-radio-frequency-study-report.

[7] See Docket No. 2016-0087, *The Hawaiian Electric Companies' Smart Grid Foundation Project*, filed March 31, 2016, Exhibit D, Attachment 3 (*Richard Tell Associates, Inc. Report of Results of An Evaluation of Radio Frequency Fields Produced by Smart Meters used by Hawaiian Electric Company – Oahu*, May 2015).

[8] These figures represent the radio waves from various common sources. The FCC MPE limit for smart meters is 600 $\mu W/cm^2$. This is for the Industrial-Scientific-Medical (ISM) frequency band from 902-928 MHz. The sources of the measurement data are: (1) Electric Power Research Institute ("EPRI"), *Radio-Frequency Exposure Levels from Smart Meters: A Case Study of One Model* (February 2011); and (2) Bailey, William H. and Shkolinkov, Yokov P., *Electromagnetic Interference and Exposure from Household Wireless Networks* (June 2011). The RF exposure level for cell phones shown in this graph is for comparison purposes only. Compliance for cell phones is provided by manufacturers and expressed in terms of Standard Absorption Rate.

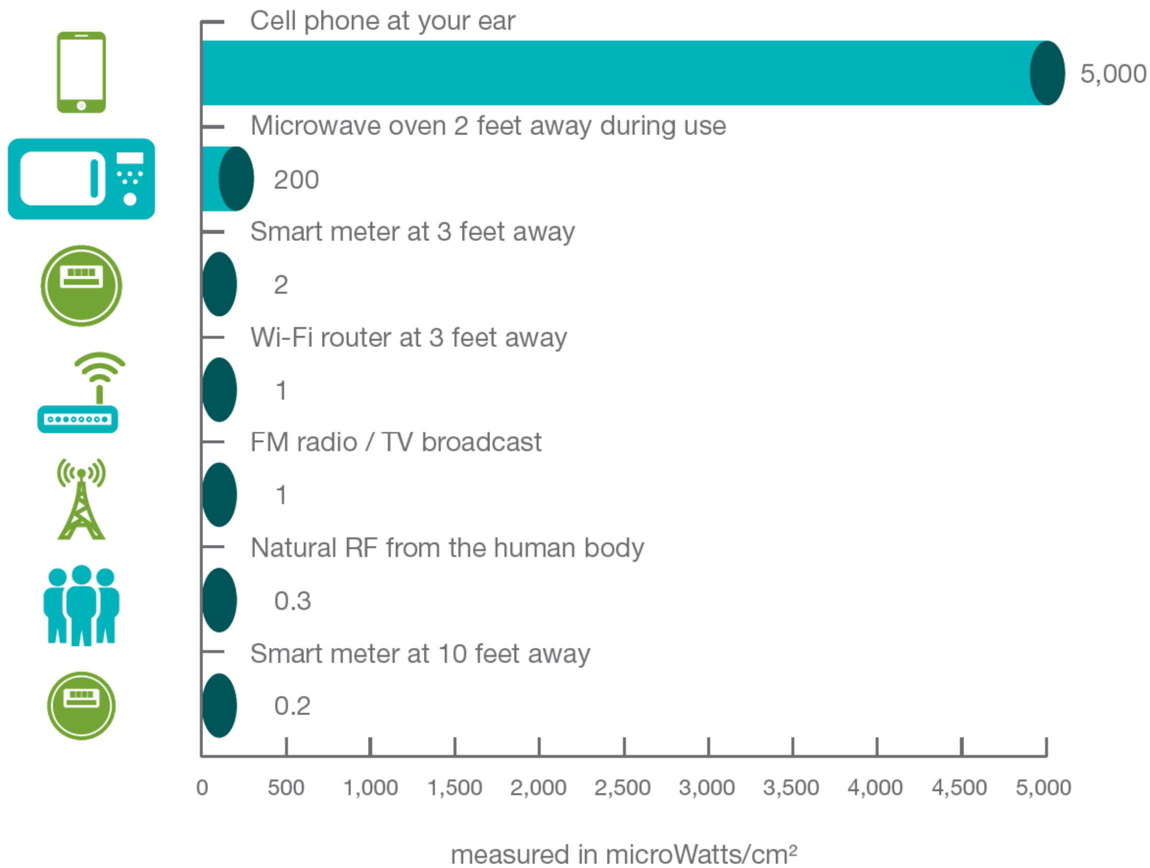

Figure 1

As shown above, in addition to being well below the limits found to be safe by the FCC, advanced meters[9] create much lower levels of RF exposure than most common household "wireless" and radio-wave devices, particularly cell phones and microwave ovens. For example, the RF emissions from a cell phone to a user's head are 2,500 times greater than the emissions from an advanced meter that is three feet away; and the RF emissions from an advanced meter that is ten feet away are less than the RF naturally emitted by the human body.

Generally, RF exposure guidelines and standards have been developed by interdisciplinary consensus groups, based on the scientific knowledge accumulated both from many years of laboratory work, and on human experience with RF waves (e.g., radio, television, navigation, telemetry, cell phones). In addition to the FCC standards for RF permissible exposure, other agencies – such as the IEEE[10] and Health Canada[11] – have standards that are

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[9] These meters are evolved versions of previous "smart meters" and provide additional functionality. See Exhibit K – *Glossary of Terms.*

[10] See Institute for Electrical and Electronic Engineers, *C95.1-2005 - IEEE Standard for Safety Levels with Respect to Human Exposure to Radio Frequency Electromagnetic Fields, 3 kHz to 300 GHz* (Apr. 19, 2006), available at

comparable to the FCC RF standards and other public health agency RF standards around the world. The safety and health concerns some customers have raised associated with RF exposure have been thoroughly vetted by external scientific investigators[12] using peer-reviewed research over the last few decades, with the most recent studies published earlier this year.[13] Since the Companies' Smart Grid Foundation Project application filing,[14] the Companies have continued to monitor new findings to determine what, if any, direct negative health effects have resulted from the use of advanced meters. These studies, which focused on low-level RF emissions by cellular devices, similar to the functional capabilities enabled by advanced meters, have shown that the overall impacts of this type of exposure do not introduce significant negative health impacts.[15] Further, as the American Cancer Society has noted:

> It would be nearly impossible to conduct a study to prove or disprove a link between living in a house with smart meters and cancer because people have so many sources of exposure to RF and the level of exposure from this source is so small. Because the amount of RF radiation you could be exposed to from a smart meter is much less than what you could be exposed to from a cell phone, it is very unlikely that living in a house with a smart meter increases risk of cancer.[16]

With that said, the Companies are aware that the International Agency for Research ("IARC") on Cancer's most recent assessment of potential health impacts associated with RF exposure from wireless phones, which was last updated in 2011, lists RF emissions as "possibly

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http://ieeexplore.ieee.org/xpl/login.jsp?tp=&arnumber=1626482&url=http%3A%2F%2Fieeexplore.ieee.org%2Fstamp%2Fstamp.jsp%3Ftp%3D%26arnumber%3D1626482 (available for purchase, free for IEEE members).

[11] See Health Canada's 2015 Update to Safety Code 6, available at http://www.hc-sc.gc.ca/ewh-semt/pubs/radiation/radio_guide-lignes_direct/index-eng.php.

[12] A recent study by the U.S. National Library of Medicine and National Institute of Health concluded in July 2017 that the results of their research found that long-term exposure to 900 MHz RF emitted by cellular phones (similar to the frequency level produced by advanced meters) "does not significantly impact DNA integrity", subsequently posing no risk to the development of cancer. See Danese, et al., *Mobile phone radiofrequency exposure has no effect on DNA double strand breaks (DSB) in human lymphocytes*, Annals of Translational Medicine, Vol. 5, No. 13, (July 5, 2017), available at https://www.ncbi.nlm.nih.gov/pmc/articles/PMC5515807/pdf/atm-05-13-272.pdf.

[13] A February 2018 study performed by the University of L'Aquila's Biotechnological and Applied Clinical Sciences Department found that exposure to radiofrequency emissions from mobile phones showed no impact on neurological receptors in the human brain, concluding that there was no causal relationship between RF exposure and human cognition. See Front. Public Health, *Exposure to Mobile Phone-Emitted Electromagnetic Fields and Human Attention* (Feb. 23, 2018), available at https://www.frontiersin.org/articles/10.3389/fpubh.2018.00042/full.

[14] See Docket No. 2016-0087, *The Hawaiian Electric Companies' Smart Grid Foundation Project*, filed March 31, 2016, Exhibit D, Attachment 2.

[15] See International Commission on Non-Ionizing Radiation Protection (ICNIRP), *Revisions of the HF Guidelines* (Dec. 7, 2017), available at https://www.icnirp.org/en/activities/news/news-article/revision-of-hf-guidelines-2017.html.

[16] See American Cancer Society, *Smart Meters*, available at https://www.cancer.org/cancer/cancer-causes/radiation-exposure/smart-meters.html.

carcinogenic."[17] The U.S. Food and Drug Administration, however, believes that "the weight of scientific evidence does not show an association between exposure to radiofrequency from cell phones and adverse health outcomes."[18] Further, the National Cancer Institute has compiled a consolidated assessment of recent scientific studies that evaluate the biological impacts of low-level RF exposure from various sources (i.e., cellular base stations, in-home Wi-Fi devices, and power lines) on children and adults, and found that there was no conclusive link between RF exposure and an increase in brain tumors, leukemia, etc.[19] Additionally, the World Health Organization has concluded that the RF emissions resulting from cellular phones have shown that "no adverse health effects have been established as being caused by mobile phone use."[20] The Companies will continue to assess new scientific evidence and correlating investigations as the grid evolves with new technologies.

C. Addressing Concerns

Importantly, acknowledging the concern that some customers have regarding RF exposure, the Companies continue to work toward offering alternative options that may appeal to individuals who prefer not to have an advanced meter installed. In particular, the Companies are evaluating two potential options. The first technical option is to evaluate the purchase of advanced meters that that have the capability to disable their communications function. This is particularly important as it gives customers the option of minimizing RF emissions while also allowing the Companies to utilize technology that the industry is shifting toward adopting almost exclusively.

The second technical option is to evaluate advanced meters with power line carrier ("PLC") capabilities that convey meter data information via power lines or other viable options. As part of the GMS implementation scope and vendor RFP assessments, the Companies will utilize the best option that addresses customer needs and concerns and is most cost-effective for the project. However, both of these options may limit a customer's ability to participate in certain programs should the functionalities of the advanced meter be modified or disabled at the customer's request. For example, Customer Grid Supply ("CGS+") requires a quick response disconnect capability to maintain grid stability. A non-communicating advanced meter would

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[17] See International Agency for Research on Cancer, *IARC Classifies Radiofrequency Electromagnetic Fields as Possibly Carcinogenic to Humans* (May 31, 2011), available at http://www.iarc.fr/en/media-centre/pr/2011/pdfs/pr208_E.pdf.

[18] See U.S. Food and Drug Administration, *Current Research Results* (updated March 7, 2018), available at https://www.fda.gov/Radiation-EmittingProducts/RadiationEmittingProductsandProcedures/HomeBusinessandEntertainment/CellPhones/ucm116335.htm.

[19] See National Cancer Institute, *Electromagnetic Fields and Cancer* (updated May 27, 2016), available at https://www.cancer.gov/about-cancer/causes-prevention/risk/radiation/electromagnetic-fields-fact-sheet#q4.

[20] See World Health Organization, *Electromagnetic field and public health: mobile phones* (originally published Oct. 8, 2014, updated August 6, 2016), available at http://www.who.int/en/news-room/fact-sheets/detail/electromagnetic-fields-and-public-health-mobile-phones.

not be able to receive the CGS+ control signal, and the PLC solution may respond too slowly to maintain grid stability. However, if technologically feasible, these options would be available for customers to consider when deciding to participate in different customer energy options.

IV. CONCLUSION

The Companies' grid modernization approach has been shaped by the input and feedback offered by customers, the Commission, stakeholders, scientific evidence, and industry leaders alike. As a result, Phase 1 of the GMS builds toward a modern grid, taking the first steps toward a platform that will support customer expectations in the right way at the right time, keeping customer concerns as a priority throughout. The Companies will be proactive in monitoring new and developing scientific research relating to the health and safety of RF emissions. Further, the Companies will continue to address potential device safety, privacy, and cybersecurity risks and issues proactively, ensuring that their systems meet applicable industry standards. The Companies will continue to address any customer and stakeholder concerns while simultaneously acknowledging technological restrictions, with the end vision as articulated in the GMS to provide customer value in the near term while building toward the State's RPS goals.

Exhibit G

GMS Phase 1 Application

Telecommunications Network Considerations

Note: References to exhibits in this document refer to exhibits included in the accompanying application unless otherwise noted.

TELECOMMUNICATIONS NETWORK CONSIDERATIONS

On August 29, 2017, the Hawaiian Electric Companies[1] submitted their Grid Modernization Strategy ("GMS"),[2] which was recently approved by the Commission.[3] The GMS outlined the Companies' vision for the future cyber-physical grid platform that will help lay the foundation for achieving Hawai'i's Renewable Portfolio Standards goal of generating 100% renewable energy by 2045.[4] The GMS was created by leveraging input from customers, stakeholders, and the vendor community, and outlines plans for grid- and customer-facing technologies enabled by a modern telecommunications network. This combination of input, when applied to the current and future needs of Hawai'i's grids, resulted in a logical and sequential two-part strategy for the Companies' future, flexible telecommunications network as articulated in the GMS. Since August 2017, the Companies' strategic approach for the telecommunications network has evolved via continued dialogue with participants of the Electric Power Research Institute ("EPRI") Telecommunication Initiative,[5] to develop procurement language for the Companies' telecommunications network request for proposal ("RFP"),[6] and the resulting vendor proposals. As a result, the proposed two-step telecommunications network approach described in the GMS will be slightly modified with a "fit for purpose" approach to roll out and expand telecommunications platform capabilities to meet both customer and grid needs.

This Phase 1 GMS Application establishes the telecommunications foundation to support the distribution grid monitoring, control, and automation needs as well as advanced metering to enable Distributed Energy Resource ("DER"), Demand Response ("DR"), and Time-of-Use ("TOU") programs that contribute to customer energy options[7]. The telecommunications network solutions proposed within this application are standards-based and follow industry best practices in an attempt to minimize costs, and avoid stranded investments, while building toward the grid the Companies' need.

In particular, the Companies intend to expand the telecommunications network proportionally to support the deployment of advanced meters included in GMS Phase 1, as well as the GMS Phase 2 deployment of field devices for distribution sensing, control, and

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[1] Hawaiian Electric Company, Inc., Hawai'i Electric Light Company, Inc., and Maui Electric Company, Limited, are collectively referred to as the "Hawaiian Electric Companies" or the "Companies."
[2] See Docket No. 2017-0226, *Modernizing Hawai'i's Grid For Our Customers* ("GMS"), filed August 29, 2017.
[3] See Docket No. 2017-0226, Decision and Order No. 35268, issued February 7, 2018.
[4] See Hawai'i Revised Statutes § 269-92.
[5] See EPRI, *2017 Annual Review and Looking Ahead to 2018: Telecommunication Initiative (Future Project Set 161G)*, available at https://www.epri.com/#/pages/product/3002012344/ (available for purchase, free for EPRI members); and
EPRI, *Information, Communication, and Cyber Security (ICCS) Roadmap* (Jan. 2017), available at https://www.epri.com/#/pages/product/3002009115/.
[6] See Exhibit D (*Request for Proposals*) and Attachments.
[7] The term "customer energy options" as utilized in this Application is inclusive of existing and new tariffs and/or programs including DR Portfolios (including TOU and future dynamic pricing) and DER programs. All of these options would be inclusive of any customer-sited resources, including but not limited to photovoltaic ("PV"), distributed storage, and electric vehicle ("EV").

automation. To support this approach, the Companies are continuing to work with the EPRI's Telecommunication Initiative team to develop a decision support tool, which can establish guidelines and parameters for their proportional telecommunications network expansion. The proportional approach of implementing a telecommunications network as needs arise will expand capabilities and incur costs over time to enable functionality as needed to meet both customer and grid needs.

In addition to the Companies identifying areas to rollout telecommunication to targeted areas for additional grid sensing and support, the Companies must also service customers that sign up for new programs. However, due to the "opt-in" approach of deploying advanced metering, customers can be located anywhere across the service territory. Therefore, the Companies will need to be flexible in identifying the appropriate telecommunication infrastructure to deploy to serve these customers. This exhibit outlines the deployment scenarios and considerations that engineers may encounter when implementing a telecommunications network that enables the Companies' vision for a modern grid, while maintaining a refined and deliberate progression.

I. TELECOMMUNICATIONS

As noted in the GMS, telecommunications is a fundamental component to enabling grid and customer-facing technologies.

> Utility communication networks are typically deployed in a layered (tiered) manner, as illustrated in [Figure 1]. At the highest level, the operations center, power plant, substations, and data centers are interconnected with a wide area network ("WAN"). The next layer is a field area network ("FAN"), which communicates between distribution substations and field devices, such as field communication routers, which link to a neighborhood area network ("NAN"), which connects intelligent switches, capacitor banks, advanced meters, and utility-managed demand response devices, such as water heaters, and A/C cycling devices.[8]

[8] See GMS, Section 7.5 (Telecommunications Infrastructure), at 94.

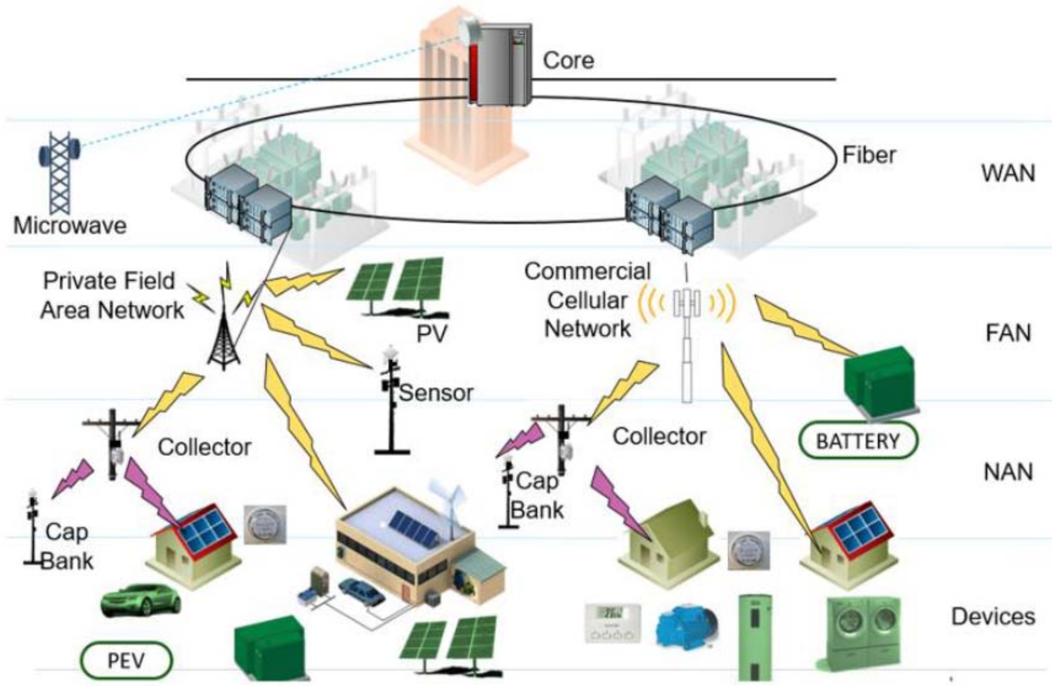

Figure 1

II. GMS TWO-PART STRATEGY FOR A TELECOMMUNICATIONS NETWORK

In the GMS, the Companies' proposed strategy for a reliable and robust telecommunications network was comprised of two incremental steps. The first step, Step 1, utilized a multi-purpose radio frequency ("RF") mesh NAN that would be capable of grid-device-level, peer-to-peer traffic. This NAN would leverage an open standard, such as Wi-SUN,[9] to link communicating field devices (i.e., intelligent switches and advanced meters), shown as one of the communication paths in Figure 2, which is a duplicate of Figure 24 filed in the GMS.[10] With a mesh network, each grid device or node on the network is capable of relaying the data from any other node on the network. The data is then relayed from node to node until the data reaches a data collector. As part of this architectural design, the NAN then utilized a commercial cellular communications backhaul, in the absence of an available FAN and WAN, to send the data to the utility's corresponding back office systems.

[9] The Wi-Sun Alliance drives interoperable Smart Utility Networks (SUN), as described by IEEE 802.15.4g, available at https://www.wi-sun.org/.
[10] See GMS, Section 7.5.2 (Strategic Approach for Building Out the Telecommunications Infrastructure), at 97.

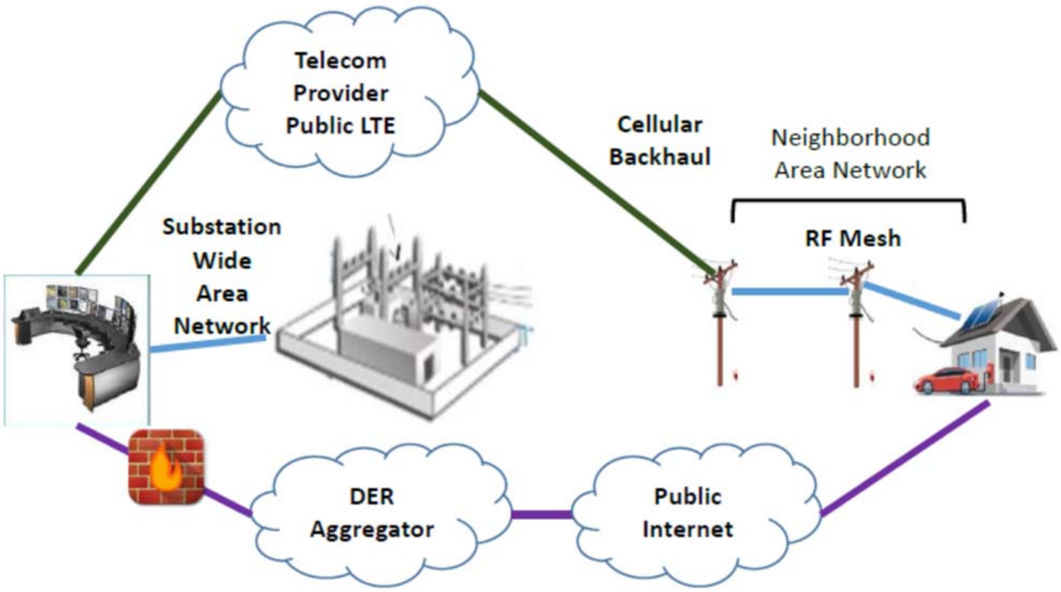

Figure 2

The next step, referenced as Step 2 in the GMS telecommunications network architecture and shown below in Figure 3, plans to leverage the WAN deployment and connect the NAN to the WAN utilizing a FAN, which could be made up of either RF mesh or fiber optic as the means for data transference. In developing the GMS, the Companies envisioned that Step 2 would "increase the telecommunication bandwidth to accommodate additional data transfer as more communicating devices are deployed; it would also reduce latency to enable a faster response."[11]

To support this, the GMS also noted that the substation's WAN deployment will continue to be expanded over time to enable supervisory control and data acquisition ("SCADA") to a sequence of prioritized distribution substations.[12] The substation WAN deployment strategy, which is outside the scope of this Application, leverages backhaul technologies such as fiber optic networking, leased wire line, or other options as available to meet SCADA bandwidth and latency requirements.

[11] Id. Section 7.5.2 (Approach for Building Out the Telecommunications Infrastructure), filed August 29, 2017, at 97.
[12] Id. Section 7.3.1 (Distribution Substation Automation), at 85.

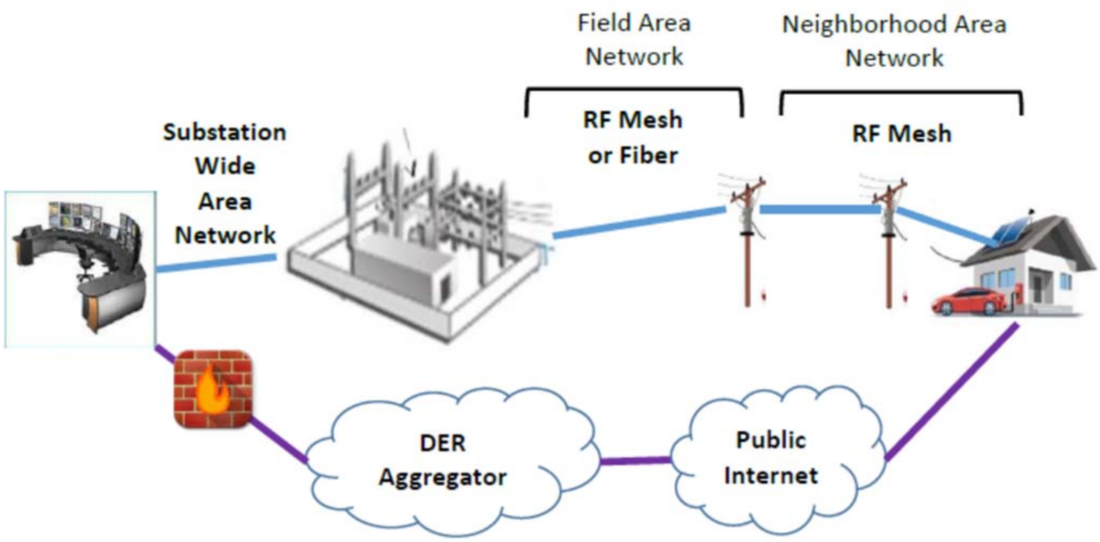

Figure 3

These two steps themselves introduce variability in the potential field deployments, as evidenced by the optionality associated with leased wire availability and mesh or fiber technologies supporting the FAN. It was not envisioned that either step would be fully deployed across the service territory within the five-year implementation timeline of the GMS, but that the telecommunications network would be deployed proportionally to support both grid and customer needs.

III. UPDATED DEPLOYMENT CONSIDERATIONS

The Companies' strategic approach for their proposed telecommunications network has evolved since the GMS filing, both because of the process to develop the procurement language, which included input from EPRI's Telecommunication Initiative,[13] and because of the vendor responses to the procurement. The vendor proposals indicate that the FAN now supports connection to the customer premise such that a technologically distinct NAN is no longer necessary. As depicted in Figure 44, the Wi-SUN Alliance defines a FAN[14] that connects backhaul options (such as cellular or fiber/Ethernet) with a host of field assets, which could include advanced meters.

[13] See 2017 Annual Review and Looking Ahead to 2018: Telecommunication Initiative (Future Project Set 161G), available at https://www.epri.com/#/pages/product/3002012344/ (available for purchase, free for EPRI members); and EPRI, Information, Communication, and Cyber Security (ICCS) Roadmap (Jan. 2017), available at https://www.epri.com/#/pages/product/3002009115/.

[14] See Wi-SUN Alliance FAN

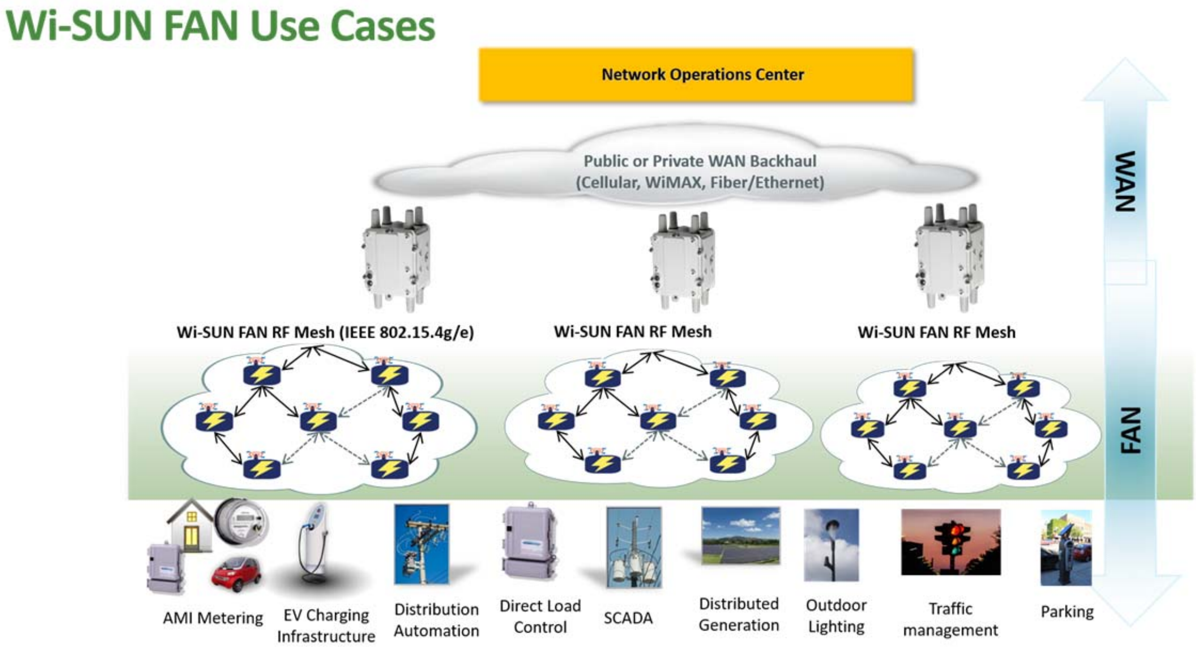

Figure 4

Within the GMS, the Companies assumed that the sequential progression from Step 1 to Step 2 might not be the most appropriate in all instances. The Companies are actively identifying the most appropriate technology deployment configurations for each situation to ensure that the telecommunications network platform utilized under the scope of GMS implementation is feasible, efficient, and the most appropriate configuration for current and future program needs. Adoption of the Wi-SUN standard is a risk mitigation approach to ensure the telecommunication solution in Hawaiʻi is not unique and aligns with industry best practices for future extensibility.

The Companies remain committed to their vision for a common multi-purpose telecommunications infrastructure to enable advanced metering as well as distribution sensing, control, and automation with field devices. The telecommunications network solution will support advanced metering for customers participating in customer energy options as well as field devices deployed to areas of the distribution grid that are experiencing issues, such as hosting capacity constraints, frequent outages, or power quality issues.

Although it is difficult for the Companies to predict how many customers will opt-in for advanced meters and where those customers will be located, the following scenarios depict likely situations the Companies will face in implementing the GMS. These scenarios for the telecommunications network are listed in no particular order; each option has different benefits and disadvantages that make it more suitable under particular conditions. Therefore, each scenario will be considered while engineering the appropriate field communications deployment for different locations. These deployment scenarios will aid the understanding of how the Companies plan to pursue a scalable and extensible telecommunications network that supports the technical communication requirements for the advanced meters and field devices, which depend on the telecommunications network for connectivity. The telecommunications network enables customer choice and provides the platform to add field devices that will help minimize outage times.

A. SCENARIO 1 – FAN TO CELLULAR

This scenario is effectively the same as what is referenced as Step 1 from the Companies' approved GMS, wherein a FAN, now also serving as the NAN, connects to telecommunication equipment serving as the cellular backhaul (or cellular takeout point) to send the data to the Companies' back office systems using LTE technology, rather than connecting to a WAN. The FAN also supports communication between peer devices for various applications, such as FLISR or distributed var control. Figure 55, below, provides a visual representation of this scenario's architecture and interrelationships when deployed on the Companies' electric grid. Here, the FAN is shown supporting communication for the field devices and meters.

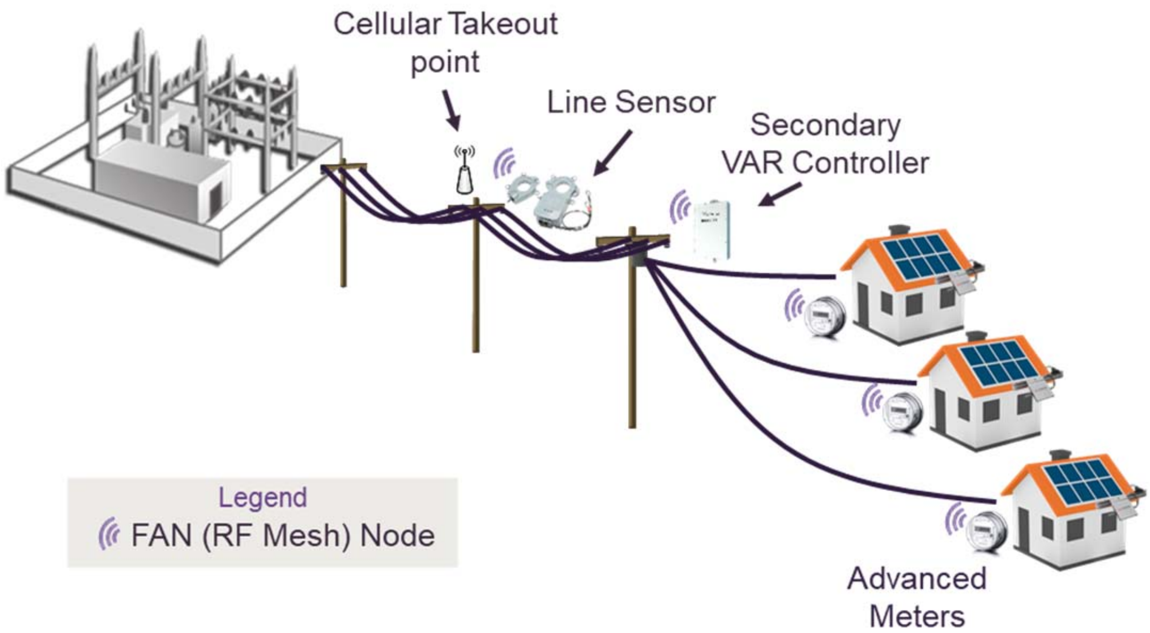

Figure 5

The Companies are also investigating the availability of advanced meters that include both radio mesh (i.e., FAN) and cellular capabilities such that a singular meter installation can act as the cellular takeout point for nearby advanced meters and any field devices that are connected to the meter via the radio mesh. This approach may be appropriate if one customer in an area enrolls in a DER or DR program, but no additional customers or field devices are immediately scheduled to be deployed in that area. Over time, the customers' neighbors would obtain advanced meters when they enroll in customer energy options or have their old meters replaced upon reaching the end of their life cycle. In that instance, the neighbors' new advanced meters could be able to communicate with the first customer's advanced meter via the FAN to access the cellular takeout point. This potential scenario is shown below in Figure 66. Accordingly, rather than each new meter independently communicating via cell, the Companies can leverage the one meter that has both FAN and cell capabilities to allow for a single cellular takeout point for all the devices in the area, as long as bandwidth and latency requirements are maintained.

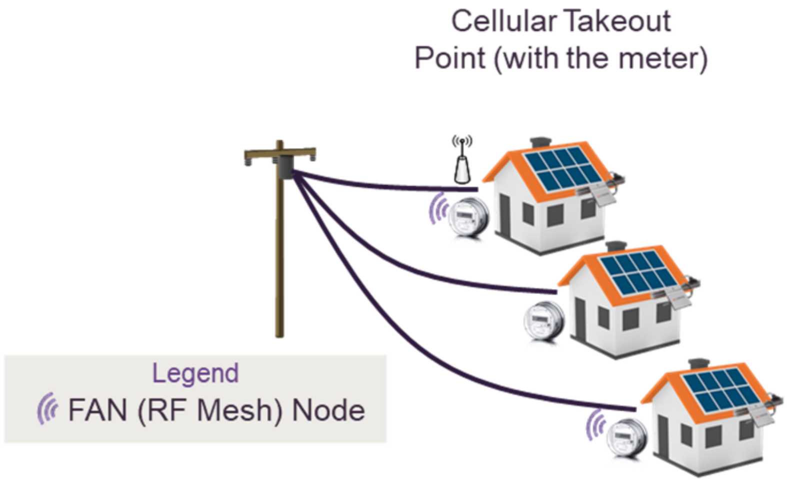

Figure 6

B. SCENARIO 2 – POWER LINE CARRIER

Power Line Carrier ("PLC") deployment is a potential option for rural areas with no reliable cellular connection, for multi-dwelling units (i.e., apartment buildings), or for customers who do not want wireless communication solutions for their advanced meters. PLC technology allows data to be sent over existing power cables. While PLC solutions may not provide bandwidth, latency, or reliability for operational purposes (e.g., control of field devices), the Companies are exploring PLC's merits as a means to enable some functionality supporting customer energy options.

Different vendor-specific options are available for PLC implementation. One option is a PLC solution to a distribution service transformer, which is either a node on the FAN or has a backhaul option to the Companies' back office systems, as depicted in Figure 77 below.

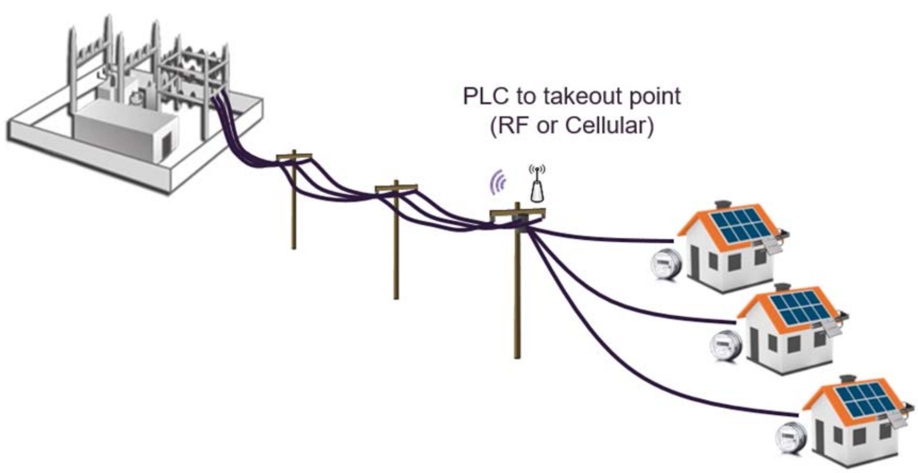

Figure 7

The other option is a PLC solution engineered to communicate all the way back to a distribution substation, where the data may utilize the WAN to communicate to the Companies' back office systems, as illustrated in Figure 88 below.

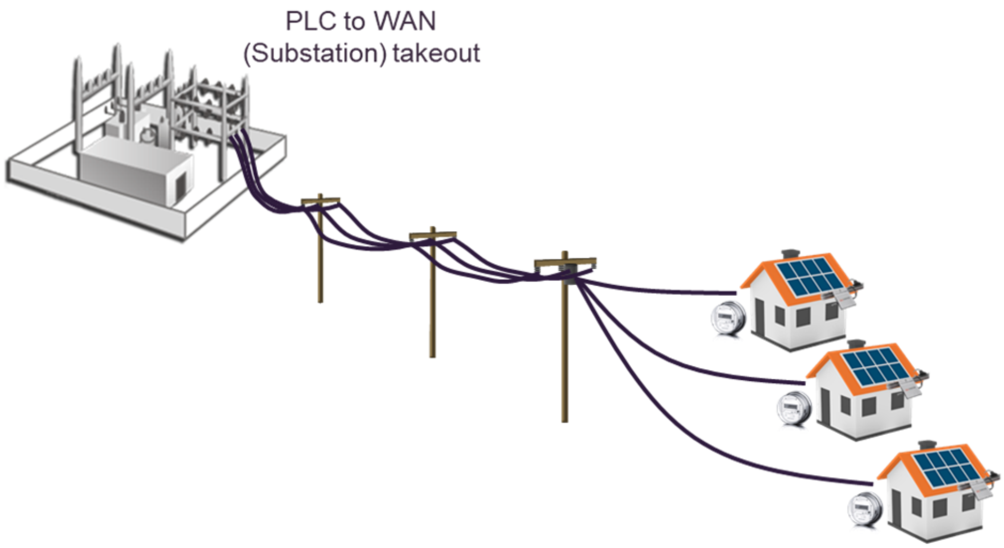

Figure 8

These two PLC choices are vendor-dependent, and options for implementation are being further explored during the telecommunication solution procurement process.

C. SCENARIO 3 – FAN TO WAN

This scenario is effectively the same as what is referenced as Step 2 from the Companies' GMS, wherein a FAN connects to the Companies' WAN, which supports distribution SCADA at the Companies' distribution substations as shown in Figure 99 below.[15] The distinction here from the GMS approach is the convergence of the NAN and FAN into a RF mesh FAN. Because the same RF mesh technology is used for both networks, the distinction between a NAN and FAN is of minimal technical value.

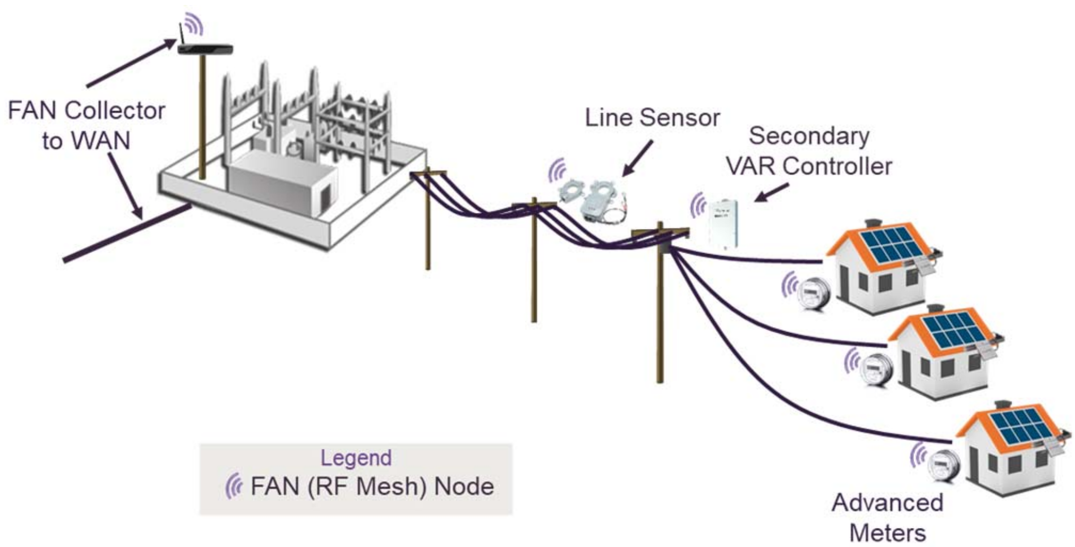

Figure 9

[15] See GMS, Section 7.3.1 (Distribution Substation Automation), at 85.

D. SCENARIO 4 – FAN TO LEASED INFRASTRUCTURE

A fourth scenario contemplates a FAN network architecture with a backhaul communications route through third-party fiber optic, cable, or telephone line infrastructure that may already be in place and available through a service plan or leased line arrangement, instead of via cellular, as shown in Figure 1010, below.

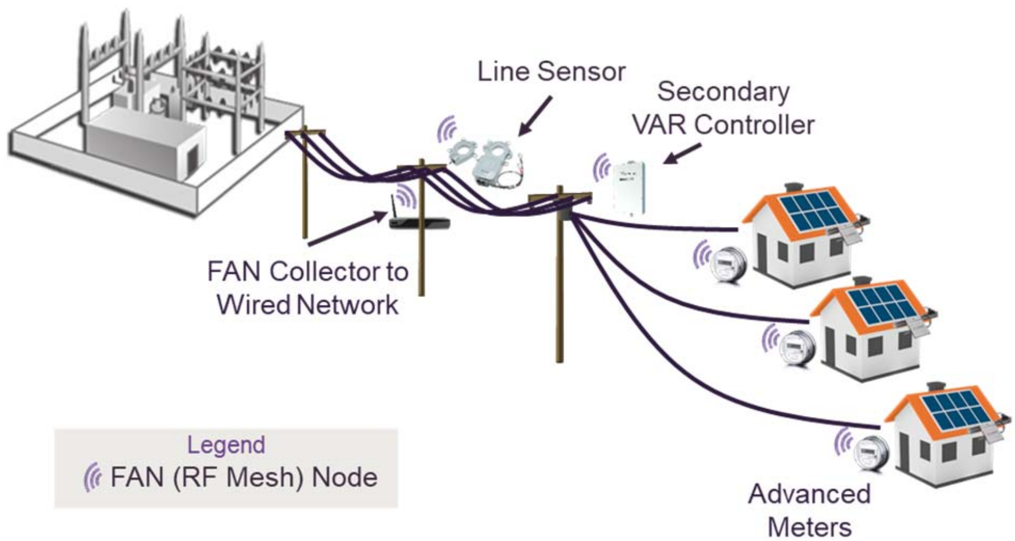

Figure 10

By utilizing existing infrastructure in a given area, the Companies would minimize redundant investment for customers. The Companies are initiating conversations with local cable and telecommunications network companies to investigate the possibility of leased line or secure connections utilizing the wired infrastructure that provides telephone, cable, and internet services. This option would not use the customers' internet service but would instead establish an internet connection on the utility pole with a local cable or wired telecommunications network.

E. IMPLEMENTATION EXAMPLES

The variables and the decisions associated with implementing and expanding a telecommunications network that is proportional to customer and grid needs is easier to conceptualize when considering specific example scenarios. The following examples provide insight into the potential options based on individual circumstances. The Companies are still evaluating the technical feasibility of these options and scenarios to meet their customers' needs.

1. Example A

A single customer in a rural area opts in to a program that requires an advanced meter. The area has no other customers nearby enrolled in programs that require advanced metering, and the cellular coverage is good in the area. In this simplistic situation, a cellular-enabled advanced meter solution could be deployed to meet this customer's needs.

2. Example B

A pair of customers in a rural area opts in to a program requiring advanced meters, and the area has no other nearby customers interested in similar programs. Cellular coverage is good in the area. In this scenario, engineers would need to assess the viability of a FAN-enabled advanced meter solution to communicate with any nearby telecommunications solution(s), which could include a cellular takeout point. Engineers would assess the need for a dedicated telecommunications network infrastructure to support the functionality needed by applying a lowest reasonable cost solution.

Another option for this example would be to serve each customer with the simple cellular-enabled advanced meter solution. When additional customers sign up in the area, the situation can be reassessed to determine whether to convert the area to a FAN, which could involve switching out existing cellular meters for radio mesh enabling meters. These cellular meters can then be redeployed to other customers signing up for programs in areas where it is not yet feasible to sustain a radio mesh. Each cellular-enabled advanced meter solution also includes built-in FAN functionality such that the meters could join a FAN without switching out the meter as more customers nearby desire advanced meter functionality.

3. Example C

A new multi-dwelling condominium complex is built in a rural coastal area. To minimize monthly cellular fees, advanced meters with PLC capability and a single cellular takeout point located nearby could be deployed to support the new complex.

4. Example D

A pair of customers in an area opts in to a program requiring an advanced meter. The area is approaching hosting capacity, and the Companies' Distribution Planning group recommends the installation of a secondary var controller ("SVC"). Cellular coverage is poor in the area, but there is a reasonable RF route to the substation, which has a WAN connection.

In this scenario, engineers could deploy a FAN to support both the advanced meters (to meet customer needs) and the SVC (to serve grid functions). The mesh network would be modeled and any supporting infrastructure, which could be in the form of communication-enabled power line sensors, would be implemented to route data to the substation and the WAN.

5. Example E

A single customer opts in to a program that requires an advanced meter. The area already has multiple customers nearby with advanced meters and a well-established mesh network. In this scenario, the customer is outfitted with an advanced meter and joins the existing FAN. This new advanced meter serves to strengthen the mesh by providing an additional node on the network, which improves the network's reliability.

6. Example F

Multiple customers along a distribution feeder opt in to a program that requires an advanced meter. One neighbor already has a radio mesh and cellular-enabled advanced meter solution that can serve as the FAN takeout point. As such, that cellular-enabled advanced meter solution could serve as the takeout point for the FAN now serving the new customers.

These examples provide insight into the real-world situations that the Companies will encounter as the telecommunications network is deployed to support customer enrollment in customer energy options, as well as to support field device deployment.

IV. ENGINEERING THE APPROPRIATE IMPLEMENTATION

As described above, the Companies are challenged with assessing the appropriate telecommunication infrastructure needs to meet the needs of customers and the grid. The Companies are continuing to work with industry experts, EPRI, to establish a framework, along with a set of guidelines and support tools for engineers to consider in implementing a multi-purpose, multi-variable field telecommunications network. Based on current grid needs to support customer expectations, the Companies have prioritized sites for the telecommunications network deployment to support areas with high penetration of DER. However, the Companies' plan remains flexible in order to address changing needs and customer participation in customer energy options. Therefore, actual deployment locations and technology strategies could be influenced by significant uptake in programs by customers in a particular location. The network deployment will support advanced meters while being extensible to support field device deployment in the future.

Once established, the network(s) will not be a static investment. As more and more customers transition to advanced meters, the Companies will need to reassess the conditions to determine what adjustments, if any, are needed to support the network. The telecommunications network architecture enables gradual build-out of bandwidth, latency, and reliability proportionate with growing customer and grid needs. A variety of factors could trigger a re-engineering of the telecommunications network, including but not limited to: (1) new advanced meters (whether from program participation, annual replacement, or new service installation); (2) changes in telecommunications network infrastructure costs; (3) changes in cellular coverage; and (4) the necessity of mesh-enabled field devices to support grid functions.

The Companies are in the process of fully understanding the implications of the various scenarios outlined above, including assessing the field and back office infrastructure necessary. The costs of each scenario will need to be considered in making the decisions for all field installations. Field infrastructure costs are contingent on a variety of factors, including intended use of the system, RF network coverage (which itself is dependent on environmental losses, weather, and geography), cellular coverage in the area, available backhaul options (e.g., leased or substation WAN), forecasted customer uptake in the area and electric grid needs for field devices in a given area. Therefore, a "fit for purpose" engineering approach to designing the field telecommunications network will be necessary to implement and proportionally expand the network. The proportional approach of implementing a telecommunications network as needs arise will expand capabilities and incur costs over time to enable functionality as needed to meet

both customer and grid needs. The proportional rollout aligns with the lowest reasonable cost approach described in the GMS.[16]

[16] See GMS, Section 4.2.1 (Lowest Reasonable Cost Method), at 43.

Exhibit H

GMS Phase 1 Application

GMS Phase 1 Project Costs

PROJECT COST ESTIMATE

Project Title: GMS Phase 1
Budget Item: **See Below**

	CONSOLIDATED			
	Telecom	**Meter**	**MDMS**	TOTAL
LABOR	[redacted]			
MATERIALS				
OUTSIDE SERVICES				
OTHER				
OVERHEAD				
AFUDC				
TOTAL COST OF PROJECT				
ESTIMATED CONTRIBUTIONS	$ -	$ -	$ -	$ -
NET PROJECT COST	[redacted]			$ 86,257,310

PROJECT COST ESTIMATE

Project Title: GMS Phase 1
Budget Item: **See Below**

	Telecom		Meter		MDMS	Telecom	Meter		MDMS	Telecom	Meter		MDMS	
	HECO	**HECO**	**HECO**	**HECO**	**HECO**	**HELCO**	**HELCO**	**HELCO**	**HELCO**	**MECO**	**MECO**	**MECO**	**MECO**	
	Network	**Headend**	**Meter**	**Headend**	**MDMS**	**Network**	**Meter**	**Headend**	**MDMS**	**Network**	**Meter**	**Headend**	**MDMS**	TOTAL
LABOR	[redacted]													
MATERIALS														
OUTSIDE SERVICES														
OTHER														
OVERHEAD														
AFUDC														
TOTAL COST OF PROJECT														$ 86,257,310
ESTIMATED CONTRIBUTIONS														$ -
NET PROJECT COST														$ 86,257,310

Confidential Information Deleted
Pursuant to Protective Order No. ____________

	Group	Hours							Dollars						
		Telecom		Meter	Telecom	Meter	Telecom	Meter	Telecom		Meter	Telecom	Meter	Telecom	Meter
		HECO	HECO	HECO	HELCO	HELCO	MECO	MECO	HECO	HECO	HECO	HELCO	HELCO	MECO	MECO
ENGINEERING		Network	Headend	Meter	Network	Meter	Network	Meter	Network	Headend	Meter	Network	Meter	Network	Meter
T&D Engineering	(BE)	[redacted]													
Project Mgt Division	(BP)														
Structural	(BT)														
Substation & Telecom	(BY														
CONSTRUCTION & MAINT															
Operations	(DS)														
TEST & SUBSTATION															
Communications	(RC)														
Instrument & Control	(RI)														
Substation	(RS)														
Construction Mgmt	(RX														
CUST INSTALLATIONS															
Engineering & Meter	(WX														
DISTRIBUTION															
Technical	(DC														
Const & Main	(DH														
Kona District	(DK														
Waimea District	(DW														
Meter	(DM														
SUPPORT SERVICES															
Electric & Welding Svcs	(VL)														
ENGINEERING															
Hilo Customer	(WC														
Kona Customer	(WK														
Total															

Exhibit I

GMS Phase 1 Application

Bill Impact

REVENUE REQUIREMENTS AND BILL IMPACTS

The Hawaiian Electric Companies[1] performed a financial analysis to forecast revenue requirements and bill impacts for Phase 1 ("Phase 1") of the Grid Modernization Strategy ("GMS"). The forecast analysis assumed a typical residential customer uses 500kWh per month. Bill impacts reflect a 30 year period for Phase 1. The forecasted bill impact excludes Phase 2 and other future replacement costs. Beyond Phase 1 (2023), the Companies will need to continue to invest in and modernize the grid. At this time the scope and scale of this future effort are not known. Technology is evolving at a rapid pace. As a result, the Companies will need to assess the needs of the customers and the grid in order to pair the appropriate technology that is available. Replacements will be included in future filings or rate cases.

Table 1 – Consolidated Revenue Requirement ($ in millions)

Year	Hawaiian Electric	Maui Electric	Hawai'i Electric Light	Consolidated
2019	0.1	-	-	0.1
2020	4.1	0.6	0.6	5.3
2021	6.8	1.6	1.7	10.1
2022	7.4	1.6	2.2	11.2
2023	7.5	1.8	2.4	11.7
2024	6.2	1.6	2.2	10.0
2025	5.9	1.5	2.1	9.5
2026	5.7	1.4	2.0	9.1
2027	5.4	1.3	2.0	8.7
2028	5.2	1.3	1.9	8.4
2029	4.9	1.3	1.8	8.0
2030	4.8	1.2	1.7	7.7
2031	4.6	1.2	1.6	7.4
2032	3.8	1.0	1.5	6.3
2033	2.2	0.6	1.2	4.0
2034	2.2	0.6	1.1	3.9
2035	2.0	0.6	1.0	3.6
2036	1.9	0.5	0.9	3.3
2037	1.8	0.4	0.8	3.0
2038	1.6	0.3	0.7	2.6
2039	1.6	0.3	0.7	2.6
2040	1.5	0.3	0.7	2.5
2041	1.5	0.3	0.6	2.4
2042	1.4	0.3	0.6	2.3
2043	1.3	0.3	0.6	2.2
2044	1.3	0.3	0.6	2.2
2045	1.2	0.3	0.5	2.0
2046	1.2	0.2	0.5	1.9
2047	1.1	0.2	0.5	1.8
2048	1.0	0.2	0.5	1.7
2049	0.9	0.2	0.4	1.5
2050	0.7	0.1	0.3	1.1
2051	0.3	0.1	0.2	0.6
2052	0.2	-	0.1	0.3
Total	99.3	23.5	36.2	159.0
NPV @	51.0	12.3	16.8	

Revenue Requirement rounded to the nearest $100,000.

[1] Hawaiian Electric, Hawai'i Electric Light and Maui Electric are collectively referred to as the "Hawaiian Electric Companies" or the "Companies."

Table 2 – Hawaiian Electric Revenue Requirement ($ in millions) and Bill Impact

Year	Meters Revenue Requirement[1]	MDMS Revenue Requirement[1]	Telecom Revenue Requirement[1]	Total Revenue Requirement[1]	Estimated MWh Sales[2]		Rate Impact cents per kWh		Bill Impact 500 kWh[3]
2019	[redacted]			0.1	6,545,100		0.0015	$	0.01
2020				4.1	6,557,000		0.0625	$	0.31
2021				6.8	6,566,500		0.1036	$	0.52
2022				7.4	6,530,600		0.1133	$	0.57
2023				7.5	6,407,600		0.1170	$	0.59
2024				6.2	6,355,400		0.0976	$	0.49
2025				5.9	6,249,900		0.0944	$	0.47
2026				5.7	6,195,700		0.0920	$	0.46
2027				5.4	6,097,300		0.0886	$	0.44
2028				5.2	5,995,200		0.0867	$	0.43
2029				4.9	5,829,800		0.0841	$	0.42
2030				4.8	5,735,300		0.0837	$	0.42
2031				4.6	5,629,600		0.0817	$	0.41
2032				3.8	5,594,700		0.0679	$	0.34
2033				2.2	5,554,500		0.0396	$	0.20
2034				2.2	5,546,900		0.0397	$	0.20
2035				2.0	5,560,800		0.0360	$	0.18
2036				1.9	5,579,400		0.0341	$	0.17
2037				1.8	5,577,000		0.0323	$	0.16
2038				1.6	5,590,300		0.0286	$	0.14
2039				1.6	5,615,900		0.0285	$	0.14
2040				1.5	5,674,100		0.0264	$	0.13
2041				1.5	5,680,000		0.0264	$	0.13
2042				1.4	5,723,300		0.0245	$	0.12
2043				1.3	5,765,700		0.0225	$	0.11
2044				1.3	5,829,900		0.0223	$	0.11
2045				1.2	5,904,600		0.0203	$	0.10
2046				1.2	5,995,800		0.0200	$	0.10
2047				1.1	6,082,800		0.0181	$	0.09
2048				1.0	6,082,800	4	0.0164	$	0.08
2049				0.9	6,082,800	4	0.0148	$	0.07
2050				0.7	6,082,800	4	0.0115	$	0.06
2051				0.3	6,082,800	4	0.0049	$	0.02
2052				0.2	6,082,800	4	0.0033	$	0.02
Total				99.3			Average	$	0.24
NPV @	23.3	19.8	7.9	51.0					

Notes:
1. Revenue Requirement rounded to the nearest $100,000.
2. Estimated Hawaiian Electric Sales (in whole $).
3. Hawaiian Electric typical residential energy consumption, per month.
4. Using 2047 forecasted sales for years thereafter.

Table 3 – Maui Electric Revenue Requirement ($ in millions) and Bill Impact

Year	Meters Revenue Requirement[1]	MDMS Revenue Requirement[1]	Telecom Revenue Requirement[1]	Total Revenue Requirement[1]	Estimated MWh Sales[2]		Rate Impact cents per kWh	Bill Impact 500 kWh[3]
2019	[redacted]	[redacted]	[redacted]	-	1,036,475		-	$ -
2020	[redacted]	[redacted]	[redacted]	0.6	1,034,996		0.0580	$ 0.29
2021	[redacted]	[redacted]	[redacted]	1.6	1,029,212		0.1555	$ 0.78
2022	[redacted]	[redacted]	[redacted]	1.6	1,029,531		0.1554	$ 0.78
2023	[redacted]	[redacted]	[redacted]	1.8	1,029,816		0.1748	$ 0.87
2024	[redacted]	[redacted]	[redacted]	1.6	1,035,676		0.1545	$ 0.77
2025	[redacted]	[redacted]	[redacted]	1.5	1,036,076		0.1448	$ 0.72
2026	[redacted]	[redacted]	[redacted]	1.4	1,036,366		0.1351	$ 0.68
2027	[redacted]	[redacted]	[redacted]	1.3	1,033,426		0.1258	$ 0.63
2028	[redacted]	[redacted]	[redacted]	1.3	1,028,445		0.1264	$ 0.63
2029	[redacted]	[redacted]	[redacted]	1.3	1,013,092		0.1283	$ 0.64
2030	[redacted]	[redacted]	[redacted]	1.2	993,498		0.1208	$ 0.60
2031	[redacted]	[redacted]	[redacted]	1.2	978,800		0.1226	$ 0.61
2032	[redacted]	[redacted]	[redacted]	1.0	975,227		0.1025	$ 0.51
2033	[redacted]	[redacted]	[redacted]	0.6	971,636		0.0618	$ 0.31
2034	[redacted]	[redacted]	[redacted]	0.6	972,002		0.0617	$ 0.31
2035	[redacted]	[redacted]	[redacted]	0.6	974,365		0.0616	$ 0.31
2036	[redacted]	[redacted]	[redacted]	0.5	980,550		0.0510	$ 0.25
2037	[redacted]	[redacted]	[redacted]	0.4	982,027		0.0407	$ 0.20
2038	[redacted]	[redacted]	[redacted]	0.3	987,218		0.0304	$ 0.15
2039	[redacted]	[redacted]	[redacted]	0.3	993,360		0.0302	$ 0.15
2040	[redacted]	[redacted]	[redacted]	0.3	1,003,171		0.0299	$ 0.15
2041	[redacted]	[redacted]	[redacted]	0.3	1,006,159		0.0298	$ 0.15
2042	[redacted]	[redacted]	[redacted]	0.3	1,012,674		0.0296	$ 0.15
2043	[redacted]	[redacted]	[redacted]	0.3	1,019,941		0.0294	$ 0.15
2044	[redacted]	[redacted]	[redacted]	0.3	1,030,534		0.0291	$ 0.15
2045	[redacted]	[redacted]	[redacted]	0.3	1,034,492		0.0290	$ 0.14
2046	[redacted]	[redacted]	[redacted]	0.2	1,042,224		0.0192	$ 0.10
2047	[redacted]	[redacted]	[redacted]	0.2	1,050,300		0.0190	$ 0.10
2048	[redacted]	[redacted]	[redacted]	0.2	1,050,300	4	0.0190	$ 0.10
2049	[redacted]	[redacted]	[redacted]	0.2	1,050,300	4	0.0190	$ 0.10
2050	[redacted]	[redacted]	[redacted]	0.1	1,050,300	4	0.0095	$ 0.05
2051	[redacted]	[redacted]	[redacted]	0.1	1,050,300	4	0.0095	$ 0.05
2052	[redacted]	[redacted]	[redacted]	-	1,050,300	4	-	$ -
Total	[redacted]	[redacted]	[redacted]	23.5			Average	$ 0.34
NPV @	5.0	4.2	3.1	12.3				

Notes:
1. Revenue Requirement rounded to the nearest $100,000.
2. Estimated Maui Electric Sales (in whole $)
3. Maui Electric typical residential energy consumption, per month.
4. Using 2047 forecasted sales for years thereafter.

Table 4 – Hawai‘i Electric Light Revenue Requirement ($ in millions) and Bill Impact

Year	Meters Revenue Requirement[1]	MDMS Revenue Requirement[1]	Telecom Revenue Requirement[1]	Total Revenue Requirement[1]	Estimated MWh Sales[2]		Rate Impact cents per kWh	Bill Impact 500 kWh[3]
2019	[redacted]	[redacted]	[redacted]	-	1,044,060		-	$ -
2020	[redacted]	[redacted]	[redacted]	0.6	1,044,291		0.0575	$ 0.29
2021	[redacted]	[redacted]	[redacted]	1.7	1,035,579		0.1642	$ 0.82
2022	[redacted]	[redacted]	[redacted]	2.2	1,029,870		0.2136	$ 1.07
2023	[redacted]	[redacted]	[redacted]	2.4	1,019,390		0.2354	$ 1.18
2024	[redacted]	[redacted]	[redacted]	2.2	1,011,421		0.2175	$ 1.09
2025	[redacted]	[redacted]	[redacted]	2.1	999,207		0.2102	$ 1.05
2026	[redacted]	[redacted]	[redacted]	2.0	985,922		0.2029	$ 1.01
2027	[redacted]	[redacted]	[redacted]	2.0	971,153		0.2059	$ 1.03
2028	[redacted]	[redacted]	[redacted]	1.9	969,870		0.1959	$ 0.98
2029	[redacted]	[redacted]	[redacted]	1.8	953,617		0.1888	$ 0.94
2030	[redacted]	[redacted]	[redacted]	1.7	944,584		0.1800	$ 0.90
2031	[redacted]	[redacted]	[redacted]	1.6	930,851		0.1719	$ 0.86
2032	[redacted]	[redacted]	[redacted]	1.5	931,394		0.1610	$ 0.81
2033	[redacted]	[redacted]	[redacted]	1.2	928,311		0.1293	$ 0.65
2034	[redacted]	[redacted]	[redacted]	1.1	929,512		0.1183	$ 0.59
2035	[redacted]	[redacted]	[redacted]	1.0	933,550		0.1071	$ 0.54
2036	[redacted]	[redacted]	[redacted]	0.9	940,270		0.0957	$ 0.48
2037	[redacted]	[redacted]	[redacted]	0.8	942,810		0.0849	$ 0.42
2038	[redacted]	[redacted]	[redacted]	0.7	947,888		0.0738	$ 0.37
2039	[redacted]	[redacted]	[redacted]	0.7	953,439		0.0734	$ 0.37
2040	[redacted]	[redacted]	[redacted]	0.7	962,348		0.0727	$ 0.36
2041	[redacted]	[redacted]	[redacted]	0.6	964,009		0.0622	$ 0.31
2042	[redacted]	[redacted]	[redacted]	0.6	970,049		0.0619	$ 0.31
2043	[redacted]	[redacted]	[redacted]	0.6	976,645		0.0614	$ 0.31
2044	[redacted]	[redacted]	[redacted]	0.6	984,980		0.0609	$ 0.30
2045	[redacted]	[redacted]	[redacted]	0.5	985,961		0.0507	$ 0.25
2046	[redacted]	[redacted]	[redacted]	0.5	989,872		0.0505	$ 0.25
2047	[redacted]	[redacted]	[redacted]	0.5	994,239		0.0503	$ 0.25
2048	[redacted]	[redacted]	[redacted]	0.5	994,239	4	0.0503	$ 0.25
2049	[redacted]	[redacted]	[redacted]	0.4	994,239	4	0.0402	$ 0.20
2050	[redacted]	[redacted]	[redacted]	0.3	994,239	4	0.0302	$ 0.15
2051	[redacted]	[redacted]	[redacted]	0.2	994,239	4	0.0201	$ 0.10
2052	[redacted]	[redacted]	[redacted]	0.1	994,239	4	0.0101	$ 0.05
Total	[redacted]	[redacted]	[redacted]	36.2			Average	$ 0.55
NPV @	9.3	4.1	3.4	16.8				

Notes:
1. Revenue Requirement rounded to the nearest $100,000.
2. Estimated Hawai'i Electric Light Sales (in whole $)
3. Hawai'i Electric Light typical residential energy consumption, per month.
4. Using 2047 forecasted sales for years thereafter.

KEY ASSUMPTIONS USED IN FINANCIAL ANALYSIS

The Companies utilized various assumptions in order to forecast revenue requirements and bill impacts. The key assumptions are highlight in the following sections.

I. COST OF CAPITAL ASSUMPTIONS

Cost of capital assumptions are based on the current approved rate case for each Company. Please refer to figures 1 through 3 below for current assumptions used in the forecast.

Figure 1 – Hawaiian Electric

HECO TY2017 Rate Case Dkt 2016-0328 Interim D&O 35100

Cost of Capital Assumptions	Weight	Rate	Weighted Average	After-Tax Weighted Average	Weighted Average Revenue Requirement	Weighted Average Gross-up for Income Taxes
Short Term Debt	1.18%	1.75%	0.02%	0.02%	0.023%	0.02%
Long Term Debt (Taxable Debt)	39.59%	5.03%	1.99%	1.48%	2.186%	1.99%
Hybrids	1.22%	7.19%	0.09%	0.07%	0.096%	0.09%
Preferred Stock	0.90%	5.37%	0.05%	0.05%	0.072%	0.07%
Common Stock	57.10%	9.50%	5.42%	5.42%	8.018%	7.31%
	100.00%		7.57%	7.032%	10.395%	9.471%

Figure 2 – Maui Electric

MECO TY2012 Rate Case Dkt 2011-0092 D&O No. 31288

Cost of Capital Assumptions	Weight	Rate	Weighted Average	After-Tax Weighted Average	Weighted Average Revenue Requirement	Weighted Average Gross-up for Income Taxes
Short Term Debt	1.23%	1.25%	0.02%	0.01%	0.017%	0.02%
Long Term Debt (Taxable Debt)	38.44%	5.06%	1.95%	1.44%	2.135%	1.95%
Hybrids	2.30%	7.32%	0.17%	0.13%	0.185%	0.17%
Preferred Stock	1.17%	8.25%	0.10%	0.10%	0.142%	0.13%
Common Stock	56.86%	9.00%	5.12%	5.12%	7.565%	6.89%
	100.00%		7.34%	6.794%	10.043%	9.151%

Figure 3 – Hawaii Electric Light

HELCO TY2016 Rate Case Dkt 2015-0170 PUC Interim D&O 34766

Cost of Capital Assumptions	Weight	Rate	Weighted Average	After-Tax Weighted Average	Weighted Average Revenue Requirement	Weighted Average Gross-up for Income Taxes
Short Term Debt	0.00%	0.00%	0.00%	0.00%	0.000%	0.00%
Long Term Debt (Taxable Debt)	40.13%	5.40%	2.17%	1.61%	2.378%	2.17%
Hybrids	1.86%	7.21%	0.13%	0.10%	0.147%	0.13%
Preferred Stock	1.31%	8.18%	0.11%	0.11%	0.159%	0.14%
Common Stock	56.69%	9.50%	5.39%	5.39%	7.961%	7.25%
	100.00%		7.79%	7.202%	10.646%	9.700%

II. TAX ASSUMPTIONS

Tax and tax credit assumptions are based on current Federal and State laws. Please refer to figure 4 below for current assumptions used in the forecast.

Figure 4 – Consolidated

		Effective
Federal Income Tax Rate	21.00%	19.74%
State Income Tax Rate	6.40%	6.02%
		25.75%
State Investment Tax Credit (ITC)		4.00%
Accelerated State ITC Amortization Period		10
Public Service Company Tax		5.885%
PUC Fee		0.500%
Franchise Tax		2.500%
Composite Revenue Tax Rate		8.885%

For forecasting purposes, state investment tax credit was applied to the total capital investment. In reality, certain costs may not be eligible for state investment tax credits. In addition, the amortization period for the state investment tax credit is assumed to be 10 years for all Companies, which is consistent with Hawaiian Electric's 2017 test year rate case. Maui Electric's 2018 test year rate case settlement proposal with the Consumer Advocate includes a 10 year amortization period. Hawai'i Electric Light's 2016 test year rate case includes a 41 year amortization period.

III. DEPRECIATION AND AMORTIZATION ASSUMPTIONS

Depreciation and amortization assumptions are based on the expected useful life of the investment. Depreciation is forecasted to begin the year after the asset is placed into service. In reality, depreciation will be based on current Commission-approved depreciation rates. Please refer to figure 5 below for current assumptions used in the forecast.

Figure 5 – Consolidated

	Advanced Meters	Meter Headend Hardware	Meter Headend Deferred	MDMS Capital	MDMS Deferred	Telecom Headend Capital	Telecom Mesh Network
Expected Useful Life	30	5	12	5	12	5	15
MACRS Tax Life ("Tax Life")	5	5	-	5	-	5	5
Tax Class Life ("Class Life")	-	-	3	-	3	-	-

IV. INVESTMENT ASSUMPTIONS

Investment assumptions are based on the forecasts of costs based on the scope of Phase 1. Please refer to figures 6 through 8 below for current assumptions used in the forecast.

Figure 6 – Hawaiian Electric

Project/Program	2019	2020	2021	2022	2023	Useful Life
Advanced Meters (Capital)	[redacted]					30
Meter Headend Hardware (Capital)						5
Meter Headend (Deferred)						12
MDMS (Capital)						5
MDMS (Deferred)						12
Telecommunication Headend (Capital)						5
Telecommunication Mesh Network (Capital)						15
TOTAL						

Figure 7 – Maui Electric

Project/Program	2019	2020	2021	2022	2023	Useful Life
Advanced Meters (Capital)	[redacted]					30
Meter Headend (Deferred)						12
MDMS (Deferred)						12
Telecommunication Mesh Network (Capital)						15
TOTAL						

Figure 8 – Hawai‘i Electric Light

Project/Program	2019	2020	2021	2022	2023	Useful Life
Advanced Meters (Capital)	[redacted]					30
Meter Headend (Deferred)						12
MDMS (Deferred)						12
Telecommunication Mesh Network (Capital)						15
TOTAL						

Exhibit J

GMS Phase 1 Application

Hawaiian Electric Companies' Decoupling Calculation Workbook

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SCHEDULE L (filed November 2019)
PAGE 1 OF 1

For first year, beginning balance is as of in-service date. Thereafter, beginning balance is January 1.

HAWAIIAN ELECTRIC COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF MAJOR PROJECT INTERIM RECOVERY
ILLUSTRATIVE MPIR PROJECT
$ in thousands

Line No.	Description	Reference	Recorded at In Service Date (Sep/Oct 2019)	Activity	Ending Balance	MPIR
	(a)	(b)	(c)	(d)	(e)	(f)
	Return on Investment					
1	Gross Plant in Service (not to exceed PUC approved amount)	Schedule L1	[redacted]			
2	Accum Depreciation	Schedule TBD				
3	Net Cost of Plant in Service					
4	CIAC	Schedule G2	-	-	-	
5	ADIT	Attachment 1A, p3	(347)	-	(347)	
6	State ITC	Attachment 1A, p3	(260)	-	(260)	
7	Total Deductions		(607)	-	(607)	
8	Total Rate Base		[redacted]			
9	Average Rate Base				[redacted]	
10	Rate of Return (grossed-up for income taxes, before revenue taxes)				9.47%	
11	Annualized Return on Investment (before revenue taxes)					[redacted]
12	Depreciation Expense (Note 1)	Schedule E / Attachment 1B			-	
13	Operating & Maintenance Expense	Schedule TBD			-	
13a	Prior year reconciliation of O&M to actuals	Schedule TBD			-	
14	Amortization of State ITC	Schedule TBD, if needed			-	
15	Lease Rent Expense	Schedule TBD, if needed			-	
16	Other Expense	Schedule TBD, if needed			-	
17	Total Expenses					$ -
18	Total Annualized Major Project Interim Recovery					[redacted]
19	Revenue Tax Factor (1/(1-8.885%))					1.0975
20	2019 Annualized Revenue for Major Project Interim Recovery					[redacted]
						To Sch B & B1

Rate of Return will be the weighted average cost of capital per the latest Commission rate case order grossed up for income taxes at the rates that apply.

Annualized amount of MPIR shown on this schedule, however, the monthly factors applied on Schedule B1 limit the MPIR for Year 1 to only the months following the in-service month.

Reconciliation to Schedule B1 (Info Only)		
Sum of Monthly Factors for Nov-Dec 2019		16.54%
Prorated MPIR for Year 1	$	127
Rev Tax Adj	$	(11)
Prorated MPIR for Year 1 excl Rev Tax	$	116

Note 1: Depreciation expense is recorded beginning in the year after an asset is placed in service, therefore, depreciation expense is zero in year 1. The revenue requirement fo
year 2 and thereafter will include the depreciation expense. See Attachment 1B.

SCHEDULE L1
(filed November 2019)

HAWAIIAN ELECTRIC COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF MAJOR PROJECT INTERIM RECOVERY
ILLUSTRATIVE MPIR PROJECT DETAIL
$ in thousands

Line No.	Grandparent # or Project #	Description	Docket No.	Actual In Service Date	Recorded at In Service Date
	(a)	(b)	(c)	(d)	(e)
1	T0007281	Meter Headend Hardware	Docket No. XXXX-XXXX	Sep 2019	[redacted]
2	T0007230	MDMS Capital	Docket No. XXXX-XXXX	Sep 2019	
3	T0007196	Telecom Headend Capital	Docket No. XXXX-XXXX	Oct 2019	
4		**Total Project Costs**			
					To Sch L

Source: Project Actuals

December 2019 in service will be combined with the 2019 annual MPIR true-up filing to be filed no later than February 2020.
MPIR to be in effect until such costs are reflected in the 2020 rate case base rates.

For first year, beginning balance is as of in-service date. Thereafter, beginning balance is January 1.

HAWAIIAN ELECTRIC COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF MAJOR PROJECT INTERIM RECOVERY
ILLUSTRATIVE MPIR PROJECT
$ in thousands

Line No.	Description	Reference	Recorded at 12/31/2019	2020 Activity	Estimated at 12/31/2020	Average 2020 Balance	MPIR
	(a)	(b)	(c)	(d)	(e)		(f)
	Return on Investment						
1	Gross Plant in Service (not to exceed PUC approved amount)	Schedule L1	[redacted]				
2	Accum Depreciation	Schedule TBD	-	(754)	(754)	(377)	
3	Net Cost of Plant in Service		[redacted]	(754)	[redacted]		
4	CIAC	Schedule G2	-	-	-	-	
5	ADIT	Attachment 1A, p1	(386)	(548)	(934)	(660)	
6	State ITC	Attachment 1A, p1	(293)	29	(264)	(279)	
7	Total Deductions		(679)	(519)	(1,198)	(939)	
8	Total Rate Base		[redacted]				
9	Average Rate Base						
10	Rate of Return (grossed-up for income taxes, before revenue taxes)					9.47%	
11	Annualized Return on Investment (before revenue taxes)						[redacted]
12	Depreciation Expense (Note 1)	Schedule E / Attachment 1B				754	
13	Operating & Maintenance Expense	Schedule TBD				-	
13a	Prior year reconciliation of O&M to actuals	Schedule TBD				-	
14	Amortization of State ITC	see line 6				(29)	
15	Lease Rent Expense	Schedule TBD, if needed					
16	Other Expense	Schedule TBD, if needed				-	
17	Total Expenses						[redacted]
18	Total Major Project Interim Recovery						
19	Revenue Tax Factor (1/(1-8.885%))						1.0975
20	2020 Annualized Revenue for Major Project Interim Recovery						[redacted]
							To Sch B & B1

Note 1: Depreciation expense is recorded beginning in the year after an asset is placed in service, therefore, depreciation expense is zero in year 1. The revenue requirement for year 2 and thereafter will include the depreciation expense. See Attachment 1B.

SCHEDULE L1
(filed February 2020)

HAWAIIAN ELECTRIC COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF MAJOR PROJECT INTERIM RECOVERY
ILLUSTRATIVE MPIR PROJECT DETAIL
$ in thousands

Line No.	Grandparent # or Project #	Description	Docket No.	Actual In Service Date	Recorded at In Service Date
	(a)	(b)	(c)	(d)	(e)
1	T0007281	Meter Headend Hardware	Docket No. XXXX-XXXX	Sep 2019	[redacted]
2	T0007230	MDMS Capital	Docket No. XXXX-XXXX	Sep 2019	
3	T0007196	Telecom Headend Capital	Docket No. XXXX-XXXX	Oct 2019	
4	T0007225/7678	Advanced Meters	Docket No. XXXX-XXXX	Monthly 2019	
5	T0007195	Telecom Mesh Network	Docket No. XXXX-XXXX	Monthly 2019	
6		**Total MPIR Project Costs**			
					To Sch L

Source: Project Actuals

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Pursuant [redacted]

HAWAIIAN ELECTRIC CO., INC.
GRID MOD
DECEMBER 31, 2019 ESTIMATE

		source	2019 Tax Depreciation	AFUDC	Tax Capitalized Interest	State ITC	Total	2020 Tax Depreciation
	FEDERAL DEFERRED TAXES							
1	Tax Difference		[redacted]					
2	Add back Book Depreciation							
3	Add back Book Amortization - State ITC							
4	Subtotal	Line 1 + 2 + 3						
5	Effective Federal Tax Rate		19.7368%	19.7368%	19.7368%	19.7368%	19.7368%	19.7368%
6	Federal Deferred Tax	Line 4 * Line 5	[redacted]					
	STATE DEFERRED TAXES							
7	Tax Difference	Line 1						
8	Add back Book Depreciation	Line 2						
9	Add back Book Amortization - State ITC	Line 3						
10	Subtotal	Line 1 + 2 + 3						
11	Effective State Tax Rate		6.0150376%	6.0150376%	6.0150376%	6.0150376%	6.0150376%	6.0150376%
12	Total State Deferred Taxes	Line 11 * Line 12	[redacted]					
13	**TOTAL DEFERRED TAXES**	Line 6 + Line 12						

NOTE> ADIT calculation resulting from total 2019 plant additions to be included in the February 2020 MPIR Filing.

HAWAIIAN ELECTRIC CO., INC.
TAX DEPRECIATION
GRID MOD

Project No.	Description	Book Basis	Less: AFUDC	Add: TCI	Tax Basis	Plant Acct	Life	Year 1 2019	Year 2 2020
v2019									
P0004170	GMS - HE Telecom FAN/NAN	[redacted]				397	5	[redacted]	
T0007196	GMS - Telecom Headend					391.1	5		
T0007225	Advanced Meter					370	5		
T0007230	GMS - HE MDMS - Capital					391.1	5		
T0007281	GMS - HE Meter Headend Hardware					391.1	5		
T0007678	GMS - HE Adv Meter - Installation					370	5		
	Total								
		*							

NOTE> No bonus depreciation on public utility property placed in service after 9/27/17.

NOTE 1> Basis includes total 2019 plant additions to be included in the February 2020 MPIR Filing.

HAWAIIAN ELECTRIC CO., INC.
GRID MOD
OCTOBER 31, 2019 ESTIMATE*

		source	2019 Tax Depreciation	AFUDC	Tax Capitalized Interest	State ITC	Total	2020 Tax Depreciation
	FEDERAL DEFERRED TAXES							
1	Tax Difference		[redacted]					
2	Add back Book Depreciation							
3	Add back Book Amortization - State ITC							
4	Subtotal	Line 1 + 2 + 3						
5	Effective Federal Tax Rate		19.7368%	19.7368%	19.7368%	19.7368%	19.7368%	19.7368%
6	Federal Deferred Tax	Line 4 * Line 5	[redacted]					
	STATE DEFERRED TAXES							
7	Tax Difference	Line 1						
8	Add back Book Depreciation	Line 2						
9	Add back Book Amortization - State ITC	Line 3						
10	Subtotal	Line 1 + 2 + 3						
11	Effective State Tax Rate		6.0150376%	6.0150376%	6.0150376%	6.0150376%	6.0150376%	6.0150376%
12	Total State Deferred Taxes	Line 11 * Line 12	[redacted]					
13	**TOTAL DEFERRED TAXES**	Line 6 + Line 12						

* ADIT calculation resulting from the September & October 2019 plant additions to be included in the November 2019 MPIR Filing.

HAWAIIAN ELECTRIC CO., INC.
TAX DEPRECIATION
GRID MOD

Project No.	Description	Book Basis	Less: AFUDC	Add: TCI	Tax Basis	Plant Acct	Life	Year 1 2019	Year 2 2020
v2019									
T0007196	GMS - Telecom Headend	[redacted]				391.1	5	[redacted]	
T0007230	GMS - HE MDMS - Capital					391.1	5		
T0007281	GMS - HE Meter Headend Hardware					391.1	5		
	Total								

NOTE> No bonus depreciation on public utility property placed in service after 9/27/17.

NOTE 1> Basis includes September & October 2019 plant additions to be included in the November 2019 MPIR Filing.

HAWAIIAN ELECTRIC CO., INC.
TAX CREDITS - GRID MODERNIZATION

State ITC Calculation	STATE *Thru Oct 2019*	STATE *2019 Total*
Total Materials & Outside Construction	[redacted]	
State ITC %	4%	4%
State ITC	[redacted]	
	10	10
Book Amort of State ITC	[redacted]	

HAWAIIAN ELECTRIC CO., INC.
AFUDC/TCI ON GRID MOD

	AFUDC 2019	0.630695 TCI 2019
P0004170	[redacted]	
T0007196		
T0007678		
T0007226		
T0007231		
Total		

Source: 2018 accrual workpapers

Hawaiian Electric Company, Inc.
Annual - TCI Incurred to AFUDC Incurred Ratio

	2013	2014	2015	2016	accrual 2017	5 Yr Ave
TCI	4,287,668	3,886,868	4,766,793	5,326,130	8,893,424	27,160,883
AFUDC	6,309,027	5,156,850	7,607,949	9,143,928	14,847,230	43,064,984
Ratio	0.679608	0.753729	0.626554	0.582477	0.598996	0.630695

HAWAIIAN ELECTRIC CO., INC.
GRID MODERNIZATION COSTS BY YEAR

Description	Meter Headend Hardware - T0007678 2019	MDMS - Capital - T0007230 2019	Telecom Headend - T0007196 2019	Total Thru Oct19	Telecom Mesh Network - P0004170 2019	Advanced Meter - T0007225 & T0007678 2019	2019 Total	
AFUDC	[redacted]							
LABOR								
MATERIALS								
OS CONTRACTS								
OTHER: OTHER COSTS								all software related
OVERHEAD								
Total								
Less AFUDC								
Add TCI								
Tax Basis								

Source: MPIR Summary excel file "Cost Estimate-Clean" tab

Hawaiian Electric Company, Inc.
2019 Major Projects Interim Recovery Depreciation Summary

[1] Grandparent # or Project #	[1] Project	Project Type	Date In Service	[1] Actual Net Plant Adds Thru 12/31/18	[1] Actual Net Plant Adds Thru 12/31/19	Plant Acct	[2] Docket No. 2010-0053 Depr Rate	2019 Depr	[3] 2020 Depr	
				(A)	(B)		(C)	(D) = (A) * (C)	(E) = (B) * (C)	
Grid Modernization Strategy Projects/Programs										
T0007281	Meter Headend Hardware	Project	2019/09	-	[redacted]	3911	0.20000	-	[redacted]	x
T0007230	MDMS Capital	Project	2019/09	-		3911	0.20000	-		x
T0007196	Telecom Headend Capital	Project	2019/10	-		397	0.06670	-		x
T0007225/ T0007678	Advanced Meter	Program	various 2019	-		370	0.02660	-		
T0007195	Telecom Mesh Network	Program	various 2019	-		397	0.06670	-		
								-		
					to Sch L (2019)				to Sch L (2020)	
								Sep/Oct 2019 PAD (sum of x)	[redacted]	
									to Att 1A	

[1] Source: Schedule L1 (Attachment 1)

[2] Depreciation rates applied will be per the latest Commission rate case order.

[3] Informational purposes only. To be included in the 2020TY rate case depreciation expense.

For first year, beginning balance is as of in-service date. Thereafter, beginning balance is January 1.

HAWAII ELECTRIC LIGHT COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF MAJOR PROJECT INTERIM RECOVERY
ILLUSTRATIVE MPIR PROJECT
$ in thousands

Line No.	Description	Reference	Recorded at In Service Date (Sep 2020)	Activity	Ending Balance	MPIR
	(a)	(b)	(c)	(d)	(e)	(f)
	Return on Investment					
1	Gross Plant in Service (not to exceed PUC approved amount)	Project Actuals	-	-	-	
2	Accum Depreciation	Schedule TBD	-	-	-	
3	Net Cost of Plant in Service		-	-	-	
4	MPIR Deferred Cost	Attachment 2C	[redacted]			
5	CIAC	Schedule G2	-	-	-	
6	ADIT	Attachment 2A, p2	(168)	-	(168)	
7	State ITC	Attachment 2A, p2	-	-	-	
8	Total Deductions		(168)	-	(168)	
9	Total Rate Base		[redacted]			
10	Average Rate Base				[redacted]	
11	Rate of Return (grossed-up for income taxes, before revenue taxes)				9.70%	
12	Annualized Return on Investment (before revenue taxes)					[redacted]
13	Depreciation Expense (Note 1)	Schedule E / Attachment 2B			-	
14	Amortization Expense	Attachment 2C			-	
15	Operating & Maintenance Expense	Schedule TBD			-	
15a	Prior year reconciliation of O&M to actuals	Schedule TBD			-	
16	Amortization of State ITC	Schedule TBD, if needed			-	
17	Lease Rent Expense	Schedule TBD, if needed			-	
18	Other Expense	Schedule TBD, if needed			-	
19	Total Expenses					
20	Total Annualized Major Project Interim Recovery					
21	Revenue Tax Factor (1/(1-8.885%))					1.0975
22	2020 Annualized Revenue for Major Project Interim Recovery					[redacted]
						To Sch B & B1

Rate of Return will be the weighted average cost of capital per the latest Commission rate case order grossed up for income taxes at the rates that apply.

Annualized amount of MPIR shown on this schedule, however, the monthly factors applied on Schedule B1 limit the MPIR for Year 1 to only the months following the in-service month.

Reconciliation to Schedule B1 (Info Only)

Sum of Monthly Factors for Oct-Dec 2020		25.20%
Prorated MPIR for Year 1	$	123
Rev Tax Adj	$	(11)
Prorated MPIR for Year 1 excl Rev Tax	$	112

Note 1: Depreciation expense is recorded beginning in the year after an asset is placed in service, therefore, depreciation expense is zero in year 1. The revenue requirement fo
year 2 and thereafter will include the depreciation expense. See Attachment 2A.

December 2020 in service programs will be combined with the 2020 annual MPIR true-up filing to be filed no later than February 2021.

SCHEDULE L (filed February 2021)
PAGE 1 of 1

For first year, beginning balance is as of in-service date. Thereafter, beginning balance is January 1.

HAWAII ELECTRIC LIGHT COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF MAJOR PROJECT INTERIM RECOVERY
ILLUSTRATIVE MPIR PROJECT
$ in thousands

Line No.	Description	Reference	Recorded at 12/31/2020	2021 Activity	Estimated at 12/31/2021	Average 2021 Balance	MPIR
	(a)	(b)	(c)	(d)	(e)		(f)
	Return on Investment						
1	Gross Plant in Service (not to exceed PUC approved amount)	Schedule L1	[redacted]	-	[redacted]		
2	Accum Depreciation	Schedule TBD	[redacted]	(175)	[redacted]	(88)	
3	Net Cost of Plant in Service		[redacted]	(175	[redacted]		
4	MPIR Deferred Cost	Attachment 2C	[redacted]	(396	[redacted]		
5	CIAC	Schedule G2	-	-	-	-	
6	ADIT	Attachment 2A, p1	(324)	(524)	(848)	(586)	
7	State ITC	Attachment 2A, p1	(74)	2	(72)	(73)	
8	Total Deductions		(398)	(522)	(920)	(659)	
9	Total Rate Base		[redacted]				
10	Average Rate Base						
11	Rate of Return (grossed-up for income taxes, before revenue taxes)					9.70%	
12	Annualized Return on Investment (before revenue taxes)						[redacted]
13	Depreciation Expense (Note 1)	Schedule E / Attachment 2B				175	
14	Amortization Expense	Attachment 2C				396	
15	Operating & Maintenance Expense	Schedule TBD				-	
15a	Prior year reconciliation of O&M to actuals	Schedule TBD				-	
16	Amortization of State ITC	see line 6				(2)	
17	Lease Rent Expense	Schedule TBD, if needed					
18	Other Expense	Schedule TBD, if needed				-	
19	Total Expenses						[redacted]
20	Total Major Project Interim Recovery						
21	Revenue Tax Factor (1/(1-8.885%))						
22	2020 Annualized Revenue for Major Project Interim Recovery						
							To Sch B & B1

Note 1: Depreciation expense is recorded beginning in the year after an asset is placed in service, therefore, depreciation expense is zero in year 1. The revenue requirement for year 2 and thereafter will include the depreciation expense. See Attachment 2A.

SCHEDULE L1
(filed February 2021)

HAWAII ELECTRIC LIGHT COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF MAJOR PROJECT INTERIM RECOVERY
ILLUSTRATIVE MPIR PROJECT DETAIL
$ in thousands

Line No.	Grandparent # or Project #	Description	Docket No.	Actual In Service Date	Recorded at In Service Date
	(a)	(b)	(c)	(d)	(e)
1	T0007235/7680	Advanced Meters	Docket No. XXXX-XXXX	Monthly 2020	[redacted]
2	T0007194	Telecom Mesh Network	Docket No. XXXX-XXXX	Monthly 2020	
3		**Total MPIR Project Costs**			
					To Sch L

Source: Project Actuals

HAWAII ELECTRIC LIGHT COMPANY, INC.
GRID MODERNIZATION
DECEMBER 31, 2020 ESTIMATE

		source	Year 1 Tax Depreciation	AFUDC	Tax Capitalized Interest	State ITC	Total	Year 2 Tax Depreciation
	FEDERAL DEFERRED TAXES							
1	Tax Difference		[redacted]					
2	Add back Book Depreciation	HELCO-WP-L-001						
3	Add back Book Amortization - Deferred Costs	HELCO-WP-L-002						
4	Add back Book Amortization - State ITC							
5	Subtotal	Line 1 + 2 + 3 + 4						
6	Effective Federal Tax Rate		19.7368%	19.7368%	19.7368%	19.7368%	19.7368%	19.7368%
7	Total Federal Deferred Taxes	Line 5 * Line 6	[redacted]					
	STATE DEFERRED TAXES							
8	Tax Difference	Line 1						
9	Add back Book Depreciation	Line 2						
10	Add back Book Amortization - Deferred Costs	Line 3						
11	Add back Book Amortization - State ITC	Line 4						
12	Subtotal	Line 1 + 2 + 3 + 4						
13	Effective State Tax Rate		6.0150376%	6.0150376%	6.0150376%	6.0150376%	6.0150376%	6.0150376%
14	Total State Deferred Taxes	Line 12 * Line 13	[redacted]					
15	**TOTAL DEFERRED TAXES**	Line 7 + Line 14						

NOTE> ADIT calculation resulting from total 2020 plant additions to be included in the February 2021 MPIR Filing.

HAWAII ELECTRIC LIGHT COMPANY, INC.
GRID MODERNIZATION
OCTOBER 31, 2020 ESTIMATE*

		source	Year 1 Tax Depreciation	AFUDC	Tax Capitalized Interest	State ITC	Total	Year 2 Tax Depreciation
	FEDERAL DEFERRED TAXES							
1	Tax Difference		[redacted]					
2	Add back Book Amortization - Deferred Costs	HELCO-WP-L-002						
3	Subtotal	Line 1 + 2						
4	Effective Federal Tax Rate		19.7368%	19.7368%	19.7368%	19.7368%	19.7368%	19.7368%
5	Total Federal Deferred Taxes	Line 3 * Line 4	[redacted]					
	STATE DEFERRED TAXES							
6	Tax Difference	Line 1	[redacted]					
8	Add back Book Amortization - Deferred Costs	Line 2						
9	Subtotal	Line 1 + 2						
10	Effective State Tax Rate		6.0150376%	6.0150376%	6.0150376%	6.0150376%	6.0150376%	6.0150376%
11	Total State Deferred Taxes	Line 9 * Line 10	[redacted]					
12	**TOTAL DEFERRED TAXES**	Line 5 + Line 11						

* ADIT calculation resulting from September 2020 deferred costs to be included in the October 2020 MPIR Filing.

HAWAII ELECTRIC LIGHT COMPANY, INC.
TAX DEPRECIATION
GRID MODERNIZATION

Project No.	Description	Book Basis	Less: AFUDC	Add: TCI	Tax Basis	Plant Acct	Life	Year 1 2020	Year 2 2021
v2020									
T0007194	Telecom Mesh Network	[redacted]				397	5	[redacted]	
T0007235	Advanced Meter					370	5		
T0007244	Meter Headend Deferred					Def	3		
T0007245	MDMS Deferred					Def	3		
T0007680	Advanced Meter - Installation					370	5		
	Total								
v2020	**Deferred Costs Only***								
T0007244	Meter Headend Deferred*	[redacted]				Def	3	[redacted]	
T0007245	MDMS Deferred*					Def	3		
	Total								

NOTE> No bonus depreciation on public utility property placed in service after 9/27/17.

NOTE 1> Basis includes deferred costs placed in-service in September 2020 to be included in the October 2020 MPIR Filing.

HAWAII ELECTRIC LIGHT COMPANY, INC.
TAX CREDITS - GRID MODERNIZATION

State ITC Calculation	**STATE** *Deferred Costs Thru Sep 2020*	**STATE** *2020 Total*
Total Materials & Outside Construction	-	[redacted]
State ITC %	4%	4%
State ITC	[redacted]	[redacted]
	41	41
Book Amort of State ITC	[redacted]	[redacted]

HAWAII ELECTRIC LIGHT COMPANY, INC.
AFUDC/TCI ON GRID MODERNIZATION

		AFUDC 2020
Telecom Mesh Network	T0007194	[redacted]
Advanced Meter	T0007235	
Meter Headend Deferred	T0007244	
MDMS Deferred	T0007245	
Advanced Meter - Installation	T0007680	
Total AFUDC		
	TCI	

Source: Tax Return workpapers

Annual - TCI Incurred to AFUDC Incurred Ratio

	2013	2014	2015	2016	2017	5 Yr Ave
TCI	584,463	398,530	521,111	674,345	512,038	2,690,487
AFUDC	906,238	654,460	819,792	1,058,589	766,523	4,205,602
Ratio	0.644933	0.608945	0.635662	0.637022	0.668001	0.639739

HAWAII ELECTRIC LIGHT COMPANY, INC.
GRID MODERNIZATION COSTS BY YEAR

	Meter Headend Deferred - T0007244	MDMS Deferred - T0007245		Telecom Mesh Network - T0007194	Advanced Meter - T0007235	Advanced Meter - Installation T0007680		
Description	2020	2020	Total Thru Sep2020	2020	2020	2020	2020 Total	
AFUDC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
LABOR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
MATERIALS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
OS CONTRACTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
OTHER: OTHER COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] all software related
OVERHEAD	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Less AFUDC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Add TCI	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Tax Basis	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

Source: MPIR Summary excel file "Cost Estimate-Clean" tab

Hawaii Electric Light Company, Inc.
2020 Major Projects Interim Recovery Depreciation Summary

[1] Grandparent # or Project #	[1] Project	Project Type	Date In Service	[1] Actual Net Plant Adds Thru 12/31/19	[1] Actual Net Plant Adds Thru 12/31/20	Plant Acct	[2] Docket No. 2009-0321 Depr Rate	2020 Depr	2021 Depr
				(A)	(B)		(C)	(D) = (A) * (C)	(E) = (B) * (C)
Grid Modernization Strategy Projects/Programs									
T0007235/ T0007680	Advanced Meter	Program	various 2020	-	[redacted]	370	0.04840	-	[redacted]
T0007194	Telecom Mesh Network	Program	various 2020	-		397	0.06670	-	
								-	
					to Sch L (2020)				**to Sch L (2021)**

Notes:

[1] Source: Schedule L1 (Attachment 2)

[2] Depreciation rates applied will be per the latest Commission rate case order.

Hawaii Electric Light Company, Inc.
MPIR Deferred Cost RAM Calculations
Summary
($ in 000's)

Line	Description	Rate Base MPIR Deferred Costs Recoverable at 9/30/20 (Note 1)	2020 Activities Additions (3 months)	2020 Activities Amortization (3 months) (Note 2)	Net Change	Rate Base MPIR Deferred Costs Recoverable at 12/31/20
1	MPIR Deferred Cost					
2	Meter Headend Deferred	[redacted]				
3	MDMS Deferred					
4	MPIR Deferred Costs Recoverable					

Notes:
(1) Source: Project Actuals

(2) Deferred cost amortization utilized a 12 year period.

Hawaii Electric Light Company, Inc.
MPIR Deferred Cost RAM Calculations
Summary
($ in 000's)

Line	Description	Rate Base MPIR Deferred Costs Recoverable at 12/31/20 (Note 1)	2021 Activities Additions (12 months)	2021 Activities Amortization (12 months) (Note 2)	Net Change	Rate Base MPIR Deferred Costs Recoverable at 12/31/21
1	MPIR Deferred Cost					
2	Meter Headend Deferred	[redacted]				
3	MDMS Deferred					
4	MPIR Deferred Costs Recoverable					

Notes:
(1) Source: Project Actuals

(2) Deferred cost amortization utilized a 12 year period.

December 2019 in service will be combined with the 2019 annual MPIR true-up filing to be filed no later than February 2020.

SCHEDULE L (filed February 2020)
PAGE 1 of 1

For first year, beginning balance is as of in-service date. Thereafter, beginning balance is January 1.

MAUI ELECTRIC COMPANY, LIMITED
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF MAJOR PROJECT INTERIM RECOVERY
ILLUSTRATIVE MPIR PROJECT
$ in thousands

Line No.	Description (a)	Reference (b)	Recorded at 12/31/2019 (c)	2020 Activity (d)	Estimated at 12/31/2020 (e)	Average 2020 Balance	MPIR (f)
	Return on Investment						
1	Gross Plant in Service (not to exceed PUC approved amount)	Schedule L1	[redacted]				
2	Accum Depreciation	Schedule TBD	-	(15)	(15)	(8)	
3	Net Cost of Plant in Service		[redacted]				
4	CIAC	Schedule G2	-	-	-	-	
5	ADIT	Attachment 3A, p1	(21)	(34)	(55)	(38)	
6	State ITC	Attachment 3A, p1	(12)	1	(11)	(11)	
7	Total Deductions		(33)	(33)	(66)	(49)	
8	Total Rate Base		[redacted]				
9	Average Rate Base						
10	Rate of Return (grossed-up for income taxes, before revenue taxes)					9.15%	
11	Annualized Return on Investment (before revenue taxes)					[redacted]	
12	Depreciation Expense (Note 1)	Schedule E					
13	Operating & Maintenance Expense	Schedule TBD					
13a	Prior year reconciliation of O&M to actuals	Schedule TBD					
14	Amortization of State ITC	see line 6					
15	Lease Rent Expense	Schedule TBD, if needed					
16	Other Expense	Schedule TBD, if needed					
17	Total Expenses						
18	Total Major Project Interim Recovery						
19	Revenue Tax Factor (1/(1-8.885%))						
20	2020 Annualized Revenue for Major Project Interim Recovery						
							To Sch B & B1

Note 1: Depreciation expense is recorded beginning in the year after an asset is placed in service, therefore, depreciation expense is zero in year 1. The revenue requirement for year 2 and thereafter will include the depreciation expense. See Attachment 3B.

MAUI ELECTRIC COMPANY, LIMITED
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF MAJOR PROJECT INTERIM RECOVERY
ILLUSTRATIVE MPIR PROJECT DETAIL
$ in thousands

Line No.	Grandparent # or Project #	Description	Docket No.	Actual In Service Date	Recorded at In Service Date
	(a)	(b)	(c)	(d)	(e)
1	T0007234/7679	Advanced Meters	Docket No. XXXX-XXXX	Monthly 2019	[redacted]
2	T0000545	Telecom Mesh Network	Docket No. XXXX-XXXX	Monthly 2019	
3		**Total MPIR Project Costs**			
					To Sch L

Source: Project Actuals

MAUI ELECTRIC COMPANY, LTD.
GRID MODERNIZATION
DECEMBER 31, 2019 ESTIMATE

		source	Year 1 Tax Depreciation	AFUDC	Tax Capitalized Interest	State ITC	Total	Year 2 Tax Depreciation
	FEDERAL DEFERRED TAXES							
1	Tax Difference		[redacted]					
2	Add back Book Depreciation	MECO-WP-L-001	[redacted]					
3	Add back Book Amortization - Deferred Costs	MECO-WP-L-002	[redacted]					
4	Add back Book Amortization - State ITC		[redacted]					
5	Subtotal	Line 1 + 2 + 3 + 4	[redacted]					
6	Effective Federal Tax Rate		19.7368%	19.7368%	19.7368%	19.7368%	19.7368%	19.7368%
7	Total Federal Deferred Taxes	Line 5 * Line 6	[redacted]					
	STATE DEFERRED TAXES		[redacted]					
8	Tax Difference	Line 1	[redacted]					
9	Add back Book Depreciation	Line 2	[redacted]					
10	Add back Book Amortization - Deferred Costs	Line 3	[redacted]					
11	Add back Book Amortization - State ITC	Line 4	[redacted]					
12	Subtotal	Line 1 + 2 + 3 + 4	[redacted]					
13	Effective State Tax Rate		6.0150376%	6.0150376%	6.0150376%	6.0150376%	6.0150376%	6.0150376%
14	Total State Deferred Taxes	Line 12 * Line 13	[redacted]					
15	**TOTAL DEFERRED TAXES**	Line 7 + Line 14	[redacted]					

NOTE> ADIT calculation resulting from total 2019 plant additions to be included in the February 2020 MPIR Filing.

MAUI ELECTRIC COMPANY, LTD.
TAX DEPRECIATION
GRID MODERNIZATION

Project No.	Description	Book Basis	Less: AFUDC	Add: TCI	Tax Basis	Plant Acct	Life	Year 1 2019	Year 2 2020
v2019									
T0000545	Telecom Mesh Network	[redacted]				397	5	[redacted]	
T0007234	Advanced Meter					370	5		
T0007679	Advanced Meter - Installation					370	5		
	Total								

NOTE> No bonus depreciation on public utility property placed in service after 9/27/17.

MAUI ELECTRIC COMPANY, LTD.
TAX CREDITS - GRID MODERNIZATION

State ITC Calculation	**STATE** *2019 Total*
Total Materials & Outside Construction	[redacted]
State ITC %	4%
State ITC	[redacted]
Amort. life	10
Book Amort of State ITC	[redacted]

MAUI ELECTRIC COMPANY, LTD.
AFUDC/TCI ON GRID MODERNIZATION

		AFUDC 2019	TCI 2019 (0.539097)
Telecom Mesh Network	T0000545	[redacted]	
Advanced Meter	T0007234		
Meter Headend Deferred	T0007240		
MDMS Deferred	T0007242		
Advanced Meter - Installation	T0007679		
Total AFUDC			

0.539097

TCI [redacted]

Source: Tax Return workpapers

Annual - TCI Incurred to AFUDC Incurred Ratio

	2013	2014	2015	2016	2017	5 Yr Ave
TCI	196,046	406,627	588,751	701,249	826,310	2,718,983
AFUDC	636,773	698,705	957,760	1,266,387	1,483,962	5,043,587
Ratio	0.307874	0.581972	0.614717	0.553740	0.556827	0.539097

MAUI ELECTRIC COMPANY, LTD.
GRID MODERNIZATION COSTS BY YEAR

	Telecom Mesh Network - T0000545	Advanced Meter - T0007234	Advanced Meter - Installation T0007679	
Description	2019	2019	2019	2019 Total
AFUDC	[redacted]			
LABOR				
MATERIALS				
OS CONTRACTS				
OTHER: OTHER COSTS				
OVERHEAD				
Total				
Less AFUDC				
Add TCI				
Tax Basis				

Source: MPIR Summary excel file "Cost Estimate-Clean" tab

Maui Electric Company, Ltd.
2019 Major Projects Interim Recovery Depreciation Summary

[1] Grandparent # or Project #	[1] Project	Project Type	Date In Service	[1] Actual Net Plant Adds Thru 12/31/18	[1] Actual Net Plant Adds Thru 12/31/19	Plant Acct	[2] Docket No. 2009-0286 Depr Rate	2019 Depr	2020 Depr
				(A)	(B)		(C)	(D) = (A) * (C)	(E) = (B) * (C)
Grid Modernization Strategy Projects/Programs									
T0007234/ T0007679	Advanced Meter	Program	various 2019	-	[redacted]	370	0.01920	-	[redacted]
T0000545	Telecom Mesh Network	Program	various 2019	-		397	0.06670	-	
					to Sch L (2019)			-	to Sch L (2020)

Notes:

[1] Source: Schedule L1 (Attachment 2)

[2] Depreciation rates applied will be per the latest Commission rate case order.
The Maui depreciation rate will be applied for illustrative purposes.

Exhibit K

GMS Phase 1 Application

Glossary of Terms

Note: This glossary is provided to clarify industry and technology terms, leveraging the glossary used in the final Grid Modernization Strategy, *Modernizing Hawai'i's Grid For Our Customers*, filed August 29, 2017 in Docket No. 2017-0226.

GLOSSARY OF TERMS

A

Advanced Distribution Management Systems (ADMS)
Software platforms that integrate numerous operational systems, provide automated outage restoration, and optimize distribution grid performance. ADMS components and functions can include distribution management system (DMS); demand response management system (DRMS); automated fault location, isolation, and service restoration (FLISR); conservation voltage reduction (CVR); and volt-var optimization (VVO).

Advanced Meter
Meters capable of two-way communication, advanced power measurement, computing platform, outage and service quality information, service switch.

C

Cellular Backhaul
The portion of the telecommunications network that uses mobile phone frequencies to connect the substation to a node in the larger network.

Community-Based Renewable Energy (CBRE)
Programs that allow customers who do not or cannot own rooftop solar panels to participate in community-based programs. Customers who participate purchase interests in the electricity generated by a developer and receive monthly credit from the utility for their portion of the electricity produced.

Customer Grid-Supply Plus (CGS+)
This program allows customers to export electricity from their own private sources (such as rooftop solar) to the grid and gives customers a monthly bill credit against the cost of the energy customers pull from the grid.

Customer Information System (CIS)
The repository of customer data required for billing and collection purposes. CIS is used to produce bills from rate or pricing information and usage determinants from meter data collection systems and/or manual processes.

D

Demand Response (DR)
Programs to incentivize modification of customer electricity usage to align with available supply (e.g., direct load control, Fast DR, and Energy Scout), including dynamic rate structures (e.g., Time of Use); currently operating under a two-year program and budget-approval cycle.

Demand Response Management System (DRMS)
A software solution used to administer and operationalize DR aggregations and programs. Building on a legacy of telephone calls requesting load reduction, DRMS uses a one-way or two-way communication link to effect control over and gather information from enrolled systems, including some commercial and industrial loads, and residential devices such as pool pumps, air conditioners and water heaters. DRMS allows DR capacity to be scaled in a cost-effective manner by automating the manual events that are typically used to execute DR events, as well as most aspects of settlement.

Distributed Energy Resource (DER)
Includes distributed generation resources, distributed energy storage, demand response, energy efficiency and electric vehicles that are connected to the electric distribution power grid and behind-the-meter at a customer's premises.

Distributed Energy Resource (DER) Aggregator
A third-party service that works with customers to put together resources and provide grid services.

Distributed Energy Resource Management System (DERMS)
A software-based solution that increases an operator's real-time visibility into the status of DER, and allows for the heightened level of control and flexibility necessary to optimize DER and distribution grid operation. A DERMS can also be used to monitor and control DER aggregations, forecast DER capability, and communicate with other enterprise systems and DER aggregators.

Distributed Generation (DG)
An industry term that refers to a small generator located at or near where the electricity will be used and is attached to the distribution grid. DG can be either a primary or secondary source of power and uses a variety of technologies, such as combustion turbines, solar rooftop panels, and wind turbines.

Distributed Generation Interconnection Plan (DGIP)
A plan ordered by the Commission by which the Companies shall address the challenges and

discuss strategies and action plans to increase distributed generation capacity in their systems while maintaining a reliable system.

Distribution Operations Center (DOC)
A DOC is the physical location for distribution operators to interface with management systems like DMS, OMS, GIS, and DERMS in order to manage the distribution system with situational awareness data and substation and distribution automation technologies.

E

Electric Power Research Institute (EPRI)
The Electric Power Research Institute conducts research, development, and demonstration projects for the benefit of the public in the United States and internationally. As an independent, nonprofit organization for public interest energy and environmental research, EPRI focuses on electricity generation, delivery, and use in collaboration with the electricity sector, its stakeholders, and others to enhance the quality of life by making electric power safe, reliable, affordable, and environmentally responsible.

Electrification of Transportation (EoT)
Part of Hawai‘i’s strategic renewable resource goals is to increase the number of electric vehicles and severely reduce the use of personal vehicles that rely on fossil fuels. The Companies released their Electrification of Transportation Strategic Roadmap on March 28, 2018.

Electric vehicle (EV)
An EV refers to automobiles and other transportation vehicles that use an electric motor for propulsion, rather than a gas or diesel-burning engine.

F

Fault Location, Isolation, and Service Restoration (FLISR)
Includes the automatic sectionalizing, restoration and reconfiguration of circuits. These applications accomplish distribution automation operations by coordinating operation of field devices, software, and dedicated communications networks to automatically determine the location of a fault, and rapidly reconfigure the flow of electricity so that some or all customers can avoid experiencing outages. FLISR may also be known as Fault Detection, Isolation and Restoration (FDIR).

Field Area Network (FAN)
The second level of a tiered utility communications structure connecting distribution substations and field devices such as field routers.

G

Grid Modernization Strategy (GMS)
A plan submitted by the Companies in August 2017 that lays out near-term actions to build the foundation for meeting the State's RPS goals by 2045 while preserving the flexibility needed to adapt to future advances in technology, changes in policy, and reductions in development costs. See Docket No. 2017-0226, *Modernizing Hawai'i's Grid For Our Customers*, filed August 29, 2017.

H

Hawaiian Electric Companies (Companies)
Hawaiian Electric Company, Inc. (Hawaiian Electric), Hawai'i Electric Light Company, Inc. (Hawai'i Electric Light) and Maui Electric Company, Limited (Maui Electric) are collectively referred to herein as "Hawaiian Electric Companies" or "the Companies."

I

Integrated Grid Planning (IGP)
A customer-centric planning process involving stakeholders, subject matter experts, and technical advisors to identify resources to meet future resource, transmission, and distribution needs with minimal risk and maximum customer value; operates on a two-year cycle starting in 2019.

Integrated Resource Plan (IRP)
An umbrella planning proceeding by the California Public Utilities Commission to evaluate system needs and customer priorities during procurement processes to ensure that power generation meets environmental targets while providing a safe and reliable power supply.

M

Major Project Interim Recovery (MPIR)
A method of recovering capital and deferred project-related costs that align with Commission-issued MPIR Guidelines regarding cost recovery through the designated MPIR adjustment mechanism, as set forth in Order No. 34514, issued April 27, 2017, in Docket No. 2013-0141.

Meter Data Management System (MDMS)
A software system that stores and aggregates the new and future usage data collected from the advanced meters and serves as the system of record for meter configuration information and metered power/usage data. This software is necessary to read the meters and feed the information to the Companies' back office systems.

Meter Data Unification System (MDUS)
MDMS system integration with the CIS billing module utilizing a standardized meter data unification system.

N

Neighborhood Area Network (NAN)
The third level of a tiered utility communication structure that connects intelligent switches, capacitor banks, advanced meters, and utility managed demand response devices such as A/C cycling devices.

Net Energy Metering (NEM)
A program where excess energy produced by customer-owned renewable energy systems was sent to the electric grid and the customer's account credited using a bi-directional meter system to register the amount of energy flowing to and from the customer's premises. This program has been replaced by the Customer Grid Supply Plus and Customer Self-Supply programs.

Network Operations Center (NOC)
A physical location to house the hardware and technology of the telecommunications network and allow for network monitoring and control.

O

Outage Management System (OMS)
An OMS utilizes multiple inputs including grid monitoring devices (including advanced meters and line sensors), and customer reports (including telephone calls, and social media posts) to quickly identify outages. Integrating an OMS with other systems like a customer information system can help determine the number of customers affected by an outage and a GIS interface can help identify the likely geographic location of the root cause of an outage.

P

Photovoltaic (PV)
Also known as rooftop solar, PV refers to the method of generating power by converting sunlight into electricity through the use of solar panels.

Power Line Carrier (PLC)
A wired telecommunications alternative to an RF mesh network for conveying meter data information via power lines, fiber optics, and similar options, where available.

Power Supply Improvement Plan (PSIP)
A detailed action plan for the years 2017–2023 that describes the optimal mix of renewable resources and how the Companies can best procure these resources, develop DER programs to support the goal of 100% renewables, and improve grid reliability.

R

Radio Frequency (RF)
RF refers to a method of data transmission using the radio frequency band used for communications transmission and broadcasting. Applications such as mobile phones, TV, and radio use the frequency band of 300 MHz to 300 GHz.

Radio Frequency Mesh Network (RF mesh)
A wireless communications network made of nodes that operate on radio frequencies.

Renewable Energy Infrastructure Program (REIP)
A program to allow increases to the total base rate charge in order to recover costs of renewable energy infrastructure projects approved by the Public Utilities Commission; reviewed annually to reconcile differences between the costs to be recovered and the revenues received by the surcharge. See the Renewable Energy Infrastructure Program Surcharge approved in the Decision and Order issued on December 30, 2009, in Docket No. 2007-0416.

Renewable Portfolio Standards (RPS)
Upon the enactment of SB 2474 established under Act 95 of the Session Laws of Hawaʻi in 2004, the Public Utilities Commission can establish standards that proscribe the portions of electricity generation that shall be met by renewable energy sources.

Request for Proposal (RFP)
The Hawaiian Electric Companies adhere to industry-standard competitive bidding practices as part of the procurement practices established by the Public Utility Commission.

S

Secondary Var Controllers (SVCs)
SVCs use power electronics-based, fast-acting, decentralized shunt-var technology for voltage regulation. Other types of SVC's both absorb or inject vars at the circuit level. They can also provide system monitoring capability if a telecommunication path is available.

Smart Grid Foundation Project (SGFP)
A proposal to achieve a more resilient electric grid while meeting the Public Utility Commission's goals for renewable energy standards; ultimately this system-wide approach to grid modernization was deemed to yield insufficient benefits in regard to customer, stakeholder, and utility needs when compared with the project's costs. Instead the Commission requested a more flexible and incremental approach that resulted in the Grid Modernization Strategy. For more information on the SGFP, see Docket No. 2016-0087, filed March 31, 2016.

Smart Meter
For the purposes of this Application, smart meters, as deployed in the Smart Grid Foundation project's initial phase, are associated with the prior generation of advanced meters.

Software as a Service (SaaS)
A software solution that is delivered via cloud services and that does not require on-premises hosting or maintenance.

Supervisory Control and Data Acquisition (SCADA)
A system of remote control and telemetry used to monitor and control the transmission system and substation automation.

T

Time-of-Use Program (TOU)
A Demand Response program to incentive customers to shift their energy usage to times when solar energy production is at its highest by billing lower electrical rates when demand for electricity is lower.

V

Var
Var is the standard abbreviation for volt-ampere-reactive, written "var," which results when electric power is delivered to an inductive load such as a motor.

Validating, Editing, And Estimating (VEE)
A set of processes and algorithms within the Meter Data Management System to verify the meter data as it comes in. VEE can identify potential data issues within the meter data, such as missing intervals or inconsistent meter reads, that indicate an issue with the advanced meter or that identify usage patterns that require review or investigation.

Volt-Var Optimization (VVO)
A software module that accesses the advanced meter data for both operational/situational awareness and system studies.

W

Wide Area Network (WAN)
The highest level of a tiered utility communications structure connecting the operations centers (main and backup) that house the operational systems, power plants, substations, and data centers.

Exhibit L

GMS Phase 1 Application

Confidentiality Justification

This log (1) identifies, in reasonable detail, the information's source, character, and location; (2) states clearly the basis for the claim of confidentiality; and (3) describes, with particularity, the cognizable harm to the producing party or participant from any misuse or unpermitted disclosure of the information.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit B, pages 10, 11, 12, 13, 14	The Companies' estimated costs associated with the procurement and deployment of components within the Grid Modernization Phase 1 implementation.	Confidential commercial, vendor, financial and pricing information which falls under the frustration of legitimate government function exception of the Uniform Information Practices Act ("UIPA").[1]	Public disclosure of the confidential information could place the Company at a competitive disadvantage in future contract negotiations; impact the Company's bargaining power relative to its vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers.

[1] Haw. Rev. Stat. § 92F-13(3).

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit B, page 31	Visualization of customer voltage conditions.	Confidential customer information and critical infrastructure which falls under the frustration of legitimate government function exception and the unwarranted invasion of personal privacy exception of the UIPA.	Public disclosure of the confidential information increases risk to Company’s facilities, jeopardizes its emergency and disaster preparedness plans, and/or adversely impacts its ability to respond to potential terrorist threats. In addition, public disclosure would expose employees and/or customers to, among other things, potential victimization.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit D, pages 11 and 12	The Companies' estimated costs associated with the procurement and deployment of components within the Grid Modernization Phase 1 implementation.	Confidential commercial, vendor, financial and pricing information which falls under the frustration of legitimate government function exception of the UIPA.	Public disclosure of the confidential information could place the Company at a competitive disadvantage in future contract negotiations; impact the Company's bargaining power relative to its vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit H, pages 1, 2, 3	The Companies' estimated costs associated with the procurement and deployment of components within the Grid Modernization Phase 1 implementation.	Confidential commercial, vendor, financial and pricing information which falls under the frustration of legitimate government function exception of the UIPA.	Public disclosure of the confidential information could place the Company at a competitive disadvantage in future contract negotiations; impact the Company's bargaining power relative to its vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit I, pages 2, 3, 4, 7, 8	The Companies' estimated costs and revenue requirements associated with the procurement and deployment of components within the Grid Modernization Phase 1 implementation.	Confidential commercial, vendor, financial and pricing information which falls under the frustration of legitimate government function exception of the UIPA.	Public disclosure of the confidential information could place the Company at a competitive disadvantage in future contract negotiations; impact the Company's bargaining power relative to its vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers.

Reference	**Identification of Item**	**Basis of Confidentiality**	**Harm**
Exhibit J, pages 1-32	The Companies' estimated costs and revenue requirements associated with the procurement and deployment of components within the Grid Modernization Phase 1 implementation.	Confidential commercial, vendor, financial and pricing information which falls under the frustration of legitimate government function exception of the UIPA.	Public disclosure of the confidential information could place the Company at a competitive disadvantage in future contract negotiations; impact the Company's bargaining power relative to its vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers.

CERTIFICATE OF SERVICE

I hereby certify that I have this date served two copies of the foregoing APPLICATION OF HAWAIIAN ELECTRIC COMPANY, INC., HAWAI'I ELECTRIC LIGHT COMPANY, INC. AND MAUI ELECTRIC COMPANY, LIMITED, VERIFICATION and EXHIBITS "A"- "L", together with this CERTIFICATE OF SERVICE, by making personal service to the following at the following address:

Dean Nishina
Executive Director
Division of Consumer Advocacy
Department of Commerce and Consumer Affairs
335 Merchant Street, Room 326
Honolulu, Hawai'i 96813

DATED: Honolulu, Hawai'i June 21, 2018.

HAWAIIAN ELECTRIC COMPANY, INC.

Damon L. Schmidt