BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAIʻI

In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC. HAWAIʻI ELECTRIC LIGHT COMPANY, INC. MAUI ELECTRIC COMPANY, LIMITED dba HAWAIIAN ELECTRIC For approval to commit funds in excess of $2,500,000 for the ADMS and Field Device Components of the Phase 2 Grid Modernization Project, to Defer Certain Computer Software Development Costs, to Recover the Capital, Deferred, and Operations and Maintenance Expense Costs through the Exceptional Project Recovery Mechanism, and Related Requests.	DOCKET NO. 2019-0327

SUPPLEMENT TO AND UPDATE OF APPLICATION OF HAWAIIAN ELECTRIC COMPANY, INC., HAWAIʻI 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.

Vice President
Hawaiʻi Electric Light Company, Inc.
Maui Electric Company, Limited

P. O. Box 2750
Honolulu, Hawaiʻi 96840

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DOCKET NO. 2019-0327

UPDATED AND SUPPLEMENTED APPLICATION

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

This is an updated and supplemented Application[1] ("Application" or "Supplement") submitted by the Hawaiian Electric Companies[2] pursuant to Commission Order No. 36921, filed

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[1] The original Application in this proceeding, filed on September 30, 2019, sought approval of the advanced distribution management system ("ADMS"). By this filing, in accordance with Order No. 36921, issued December 30, 2019, which suspended the instant docket until the Companies supplemented the original ADMS Application with an application for the broad deployment of Field Devices, the Companies hereby provide the required Field Device supplement to the original ADMS Application. Further, by this filing, the Companies also update the original ADMS Application to, among other things, reflect updated ADMS costs for data repository/historian and incremental labor needs, updated Project schedule to align with deployment of Field Devices, and requested EPRM cost recovery. To the extent there are any other inconsistencies between the two, this Supplement prevails and supersedes the original Application.

[2] Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Maui Electric Company, Limited ("Maui Electric"), and Hawaiʻi Electric Light Company, Inc. ("Hawaiʻi Electric Light") are collectively the Hawaiian Electric Companies and hereinafter referred to as the "Hawaiian Electric Companies" or "Companies."

on December 30, 2019, in the subject proceeding. By this Supplement, the Hawaiian Electric Companies respectfully request the approvals necessary to commence and obtain cost recovery for the acquisition and deployment of field devices ("Field Devices") and the Advanced Distribution Management System ("ADMS") (collectively, the "Project") which constitute Phase 2 of the Companies' Grid Modernization Strategy ("GMS")[3] implementation. The Companies request approval to recover the Project costs through the Exceptional Project Recovery Mechanism ("EPRM").[4]

I. EXECUTIVE SUMMARY

The Companies' GMS set forth a plan to transform and modernize the Hawaiian Electric Companies' electric grid from a traditional one-way grid into a two-way grid that serves as a platform to integrate distributed generation systems, distributed storage systems, and flexible loads – including electric vehicle charging and customer programs to enable these technologies – while maintaining reliable and more resilient service. Phase 1 of the GMS implementation, as approved by the Commission, involved deployment of advanced meters and telecommunications that are foundational to GMS objectives. Phase 1 implementation is in progress.

Phase 2 GMS implementation – the subject of this Application – focuses on providing grid operators new tools to manage the grid, transitioning from operating system-level devices

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[3] "Modernizing Hawaii's Grid For Our Customers," filed in Docket No. 2017-0226 on August 29, 2017 ("GMS," "Grid Modernization Strategy," or "Strategy").

[4] See Docket No. 2018-0088, Decision and Order ("D&O") No. 37507, filed on December 23, 2020 ("D&O 37507"), at 84. D&O 37507 terminated the MPIR Guidelines and immediately replaced it with the EPRM Guidelines, with the exception that any pending application for MPIR relief submitted by the Companies prior to D&O 37507 would remain under the MPIR Guidelines. D&O 37507 also provided that if the Companies wish for a pending MPIR application to be reviewed under the EPRM Guidelines, they must make an affirmative written request in the appropriate docket. The Companies hereby make this request.

and unmanaged one-way flow of power toward enhanced visibility and control to understand the increasingly complex and abundant paths of electricity flow at the distribution level to manage and control two-way power flow across the distribution system. The Project will deploy Field Devices to leverage the full capability of the ADMS to, among other things, (1) enable integration of greater renewable energy, specifically DER, (2) promote DER asset effectiveness and grid investment efficiency, (3) maintain and improve grid reliability as the renewable energy resources are added, (4) establish an interoperable, standards-based system that will work with present and future components of the Companies' systems, (5) enable customer options, (6) advance electrification of transportation, and (7) realize operational efficiencies.

The total cost for Phase 2 is $104.8 million, consisting of $50.1 million for the ADMS and $54.7 million for Field Devices. This amount, plus Grid Modernization Phase 1 costs[5], will keep the full GMS implementation within the original GMS conceptual estimate of $205 million.

II. REQUESTED APPROVALS

The Hawaiian Electric Companies hereby supplement and update the Requested Approvals for the Project and respectfully request a decision and order ("D&O") approving:

(1) Implementation of the proposed Project (at a total current estimated cost of $104.3 million; ADMS at $49.6 million and the Field Devices at $54.7 million), as further described in Exhibit G (*Updated GMS Phase 2 Project Costs*);

(2) A commitment of funds in excess of $2.5 million for the capital costs of the Project (currently estimated at $56.1 million, net of customer contributions,

[5] D&O 36230 approved $86.3 million for the first phase of the Companies' Grid Modernization Strategy.

("Capital Costs") pursuant to Paragraph 2.3(g)(2) of the Commission's General Order No. 7, as modified by D&O No. 21002, filed May 27, 2004, in Docket No. 03-0257 ("G.O. 7");

(3) The proposed accounting and ratemaking treatment for the Project, as further described in Exhibit C (*Accounting and Ratemaking Treatment*), including:

(a) Deferral of the software costs of the Project (currently estimated at [redacted] million) ("Deferred Costs") 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 No. 18365, filed on February 8, 2001, in Docket No. 99-0207 ("D&O 18365");

(b) Accrual of an allowance for funds used during construction ("AFUDC"), as appropriate, while the software is under development for the Project, with a carrying cost equivalent to the AFUDC rate that would be applied to the deferred costs after the software is in use until the deferred costs are included in the rate base in determining rates;

(c) Recovery of the Capital Costs and Deferred Costs through the Exceptional Project Recovery Mechanism ("EPRM") established in D&O 37507, as described in Exhibit D;

(d) Amortization of the Deferred Costs over a period of 12 years to commence when the associated ADMS costs are recovered through the EPRM adjustment mechanism;

(4) Recovery of Operations and Maintenance ("O&M") costs as further described in Exhibit C (*Accounting and Ratemaking Treatment*), including:

(a) Recovery of the ADMS O&M costs incurred through the EPRM adjustment mechanism during the Project implementation (currently estimated at [redacted] million) in the year following when costs are incurred; and

(b) Recovery of ADMS post-implementation O&M costs through the EPRM adjustment mechanism (currently estimated at $2.66 million annually), as described in Exhibit D;

(c) Recovery of the Field Devices annual, incremental post-implementation O&M costs (currently estimated at $0.364 million annually) with recovery of both Project implementation and post-implementation O&M costs through the EPRM adjustment mechanism in the year following when costs are incurred, as described in Exhibit D;

(5) Deferral treatment of pre-implementation ADMS O&M costs incurred beginning January 1, 2021 prior to Commission approval; including recovery of the deferred ADMS O&M costs (currently estimated [redacted] through the EPRM adjustment mechanism; and

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

III. APPLICANTS

Hawaiian Electric, whose principal place of business and whose executive offices are located at 1001 Bishop Street, Suite 2500, Honolulu, Hawaiʻi, is a corporation duly organized under the laws of the Kingdom of Hawaiʻi on or about October 13, 1891, and now exists under and by virtue of the laws of the state of Hawaiʻi. Hawaiian Electric is an operating public utility engaged in the production, purchase, transmission, distribution, and sale of electricity on the island of Oʻahu.

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

Maui Electric, whose principal place of business and whose executive offices are located at 210 Kamehameha Avenue, Kahului, Maui, Hawaiʻi, is a corporation duly organized under the laws of the Territory of Hawaiʻi on or about April 28, 1921, and now exists under and by virtue of the laws of the state of Hawaiʻi. 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 Molokaʻi; and the production, purchase, distribution, and sale of electricity on the island of Lanaʻi.

IV. CORRESPONDENCE

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

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V. STATUTORY PROVISION OR AUTHORITY

The approvals in this Supplement are requested pursuant to Sections 269-6, 269-7, 269-16, 269-94, and 269-95(1) of the Hawaiʻi Revised Statutes ("HRS"), Sections 16-601-74 and 16-601-86 of the *Rules of Practice and Procedure Before the Public Utilities Commission*, Title 16, Chapter 601 of the Hawaiʻi Administrative Rules, G.O. 7 Paragraph 2.3(g)(2), D&O 18365, D&O No. 34514, issued on April 27, 2017, in Docket No. 2013-0141, D&O No. 35268 ("D&O 35368"), issued on February 7, 2018, in Docket No. 2017-0226, and D&O No. 37507.

VI. EXHIBITS

The following exhibits are provided in support of this Supplement:

Exhibit A	–	Grid Modernization Strategy Working Plan
Exhibit B	–	Updated Project Justification with Business Case Support
Exhibit C	–	Accounting and Ratemaking Treatment
Exhibit D	–	Exceptional Project Recovery
Exhibit E	–	Procurement Process
Exhibit F	–	GMS System Architecture and Cyber Security
Exhibit G	–	Updated GMS Phase 2 Project Costs
Exhibit H	–	Updated Bill Impact
Exhibit I	–	Hawaiian Electric Companies' Decoupling Calculation Workbook
Exhibit J	–	Glossary of Terms
Exhibit K	–	Siemens Field Device Strategy
Exhibit L	–	Confidentiality Justification

VII. PROJECT DESCRIPTION

The Companies are implementing the GMS in phases, as illustrated in Figure 1.[6]

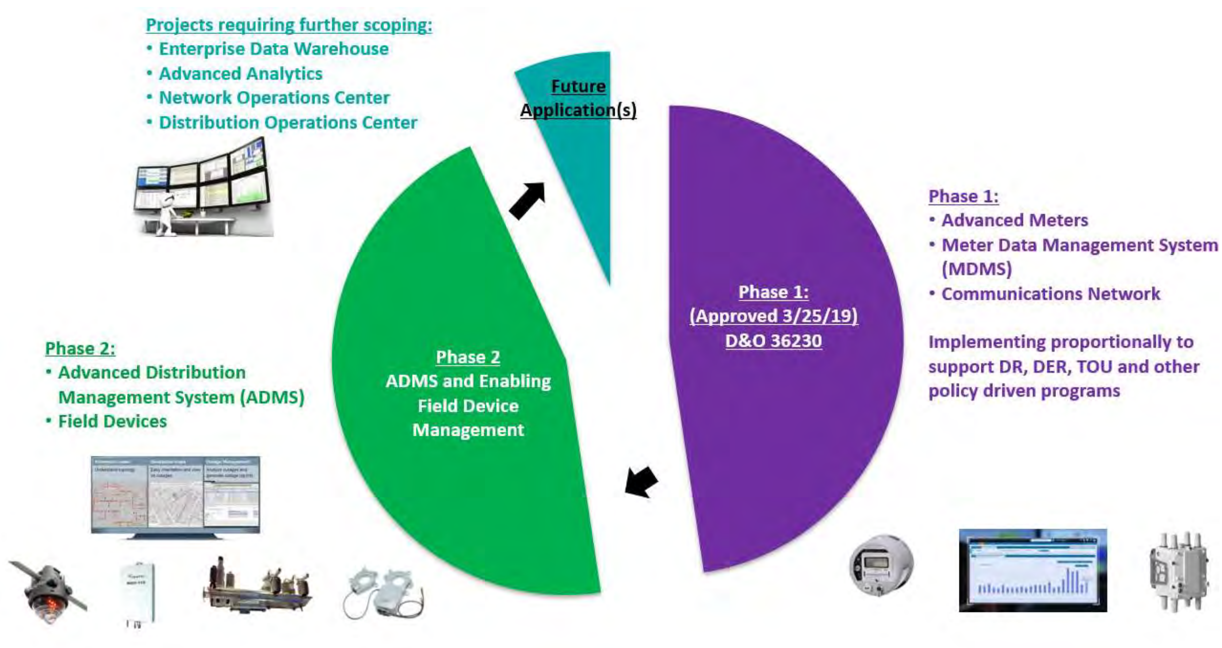


Figure 1[7]

This Project includes the Phase 2 acquisition and deployment activities, consisting of an ADMS and Field Devices, including Secondary VAR Controllers ("SVCs"), line sensors, remote fault indicators ("RFIs"), and remote intelligent switches (reclosers, smart fuses), (see Exhibit A *Grid Modernization Strategy Working Plan*) at an estimated total Project cost of $104.3 million, with $49.6 million for ADMS and $54.7 million for Field Devices.

The ADMS provides the operational tools, including the algorithms and processing power, to empower grid operators with situational awareness of the distribution system, as well

[6] See Docket No. 2018-0141, Phase 1 Grid Modernization Project Application, filed on June 21, 2018, at 18.
[7] The Enterprise Data Warehouse identified in this figure aligns with the Data Historian included in this Phase 2 application

as the control and automation necessary to monitor and operate the dynamic grid needed to support the variable and distributed resources required to achieve the State's RPS goals.

The Field Devices build upon the outage and voltage sensing and measurement capabilities provided by the Phase 1 advanced meters to provide grid operators with situational awareness and the tools needed to take preventative or corrective actions to improve the quality of electric service for customers. Many of the Field Devices provide remote sensing capabilities that will be integrated into the ADMS to be utilized by grid operators in real-time and also provide data for other processes and analytics, such as distribution planning and hosting capacity studies. The high-level device types and capabilities are captured in the Table below.

		Device Type			
		SVCs	Line Sensors	RFIs	Intelligent Switches
Capability	Sensing	X	X	X	X
	Control				X
	Automation	X			X

Table 1

A. ADMS DESCRIPTION

The ADMS component of the Project focuses on deployment and integration of a commercially available ADMS software solution for all three operating Companies. The Project will implement an ADMS in the Companies' grid control rooms that will provide greater visibility, control, and optimization of the distribution system for more reliable operations of a two-way grid with increasing DER.

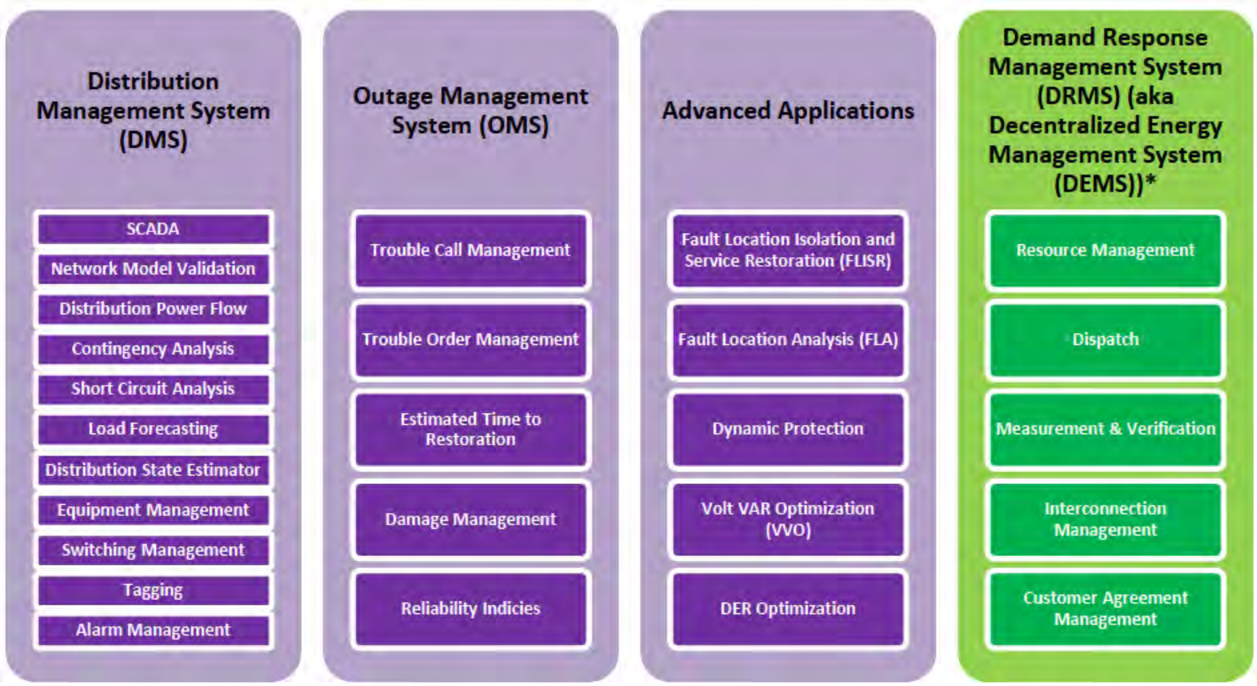
Currently, the Companies are managing the bulk power system without visibility into or control over the vast majority of distributed resources or the operating state of the distribution network. Limited tools are available, and primarily manual processes are used to operate the distribution system, with its unprecedented levels of DER penetration and widespread reverse power flows. These distributed resources have a substantial impact on both the distribution system and the bulk grid, and the lack of visibility and control over such a major component of the total grid energy is unsustainable. The ADMS will provide the grid operators the visibility and control needed to operate a modern grid while maintaining cybersecurity. This investment directly benefits customers by providing grid operators with a platform to identify and respond to both outages and power quality issues focusing on the integrated volt-Var control needed to accommodate and integrate additional DER on the distribution grid.

The solution will improve resiliency following disruptions by enhancing situational awareness and assisting in restoration triage to recover from events faster. The existing outage management processes will also be modernized to utilize the ADMS Outage Management System ("OMS") reporting and automation features that improve customer communications, incident response, and operational efficiency. At this point, only Hawaiian Electric has an OMS and it is nearing the end of its useful life. Implementing the OMS module of the ADMS will directly benefit customers of Maui Electric and Hawai'i Electric Light with improved outage identification and mitigation.

Vendor-supplied ADMS solutions are typically comprised of four foundational features: (1) an OMS used to manage and track outages; (2) a Distribution Management System ("DMS") that monitors and controls switching at the distribution level, including distribution Supervisory Control and Data Acquisition ("SCADA"), in conjunction with Field Devices; (3) "Advanced Applications" analytic functions for forecasting, simulating, studying, and optimizing the impacts of different network switching configurations and loading conditions; and (4) a

Distributed Energy Resource Management System ("DERMS"). The Companies have already implemented the DERMS through the Demand Response Management System ("DRMS") project and the resulting Decentralized Energy Management System ("DEMS") implementation.[8] The Project addresses the need to implement the remaining three modules of an ADMS. Figure 2 illustrates the four ADMS components and their various functional modules.

Industry Reference Components of an Advanced Distribution Management System



*The DEMS was implemented per Docket No. 2015-0411 D&O 36476.

Figure 2

The ADMS will also interact with other operational and corporate systems to provide context to the stream of data as described below and detailed in Exhibit F (*GMS System*

[8] See Docket No. 2015-0411

Architecture and Cyber Security). For example, the ADMS will integrate with the DEMS system to coordinate DER commands and dispatch as well as with each Company's existing Energy Management System ("EMS") to coordinate DER dispatch at the system level. Additionally, the ADMS OMS will receive outage notifications from the Phase 1 advanced meters through the meter data management system ("MDMS") as well as the distribution Field Devices described in this application.

Power quality voltage issues have become more prevalent with higher DER penetration and will become more progressive and visible to customers as more customer DER is utilized to attain RPS goals. ADMS integrated volt-VAR controls and SVCs will help proactively mitigate voltage issues rather than just being reactive to customer complaints. As circuits host more DER, the voltage becomes more variable causing power quality issues for customers.[9] For example, an increase in customer electricity demand relative to the available electricity supply results in a voltage drop, and a drop in customer demand relative to the available supply results in a voltage increase.[10] For voltage monitoring and control, the ADMS will receive notifications from the Phase 1 advanced meters when configured thresholds are exceeded and the distribution Field Devices will also provide voltage alerts. Voltage issues can then be mitigated with ADMS integrated volt-Var controls using substation automation (e.g. cap bank controllers), SVCs, and increasing interconnection of advanced inverters.[11] Voltage monitoring and control is an

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[9] See Docket No. 2014-0192, Proceeding to Investigate Distributed Energy Resource Policies - Distribution Circuit Monitoring Program Plan, March 9, 2017.

[10] Referencing relevant standards, American National Standards Institute ("ANSI") C84.1 specifies utility service voltage as ±5% (e.g., 114-126 V for 120V service). American National Standards Institute ("ANSI") specifies ±10% voltage range for consumer electronics. As a result, voltage exceeding ANSI standards can result in damage to customer equipment.

[11] See Rule 14

operational priority in order to interconnect more DER while providing the standard of service customers expect.[12] Deploying the components within this Application would greatly enhance our ability to perform this priority by extending voltage monitoring and control to the grid edge.

One of the activities vital to enabling full value from an ADMS implementation is to review and verify enterprise and asset information to build an accurate grid network model and associate customers with their connected transformer. Most ADMS functionality builds from an accurate network model used to provide situational awareness to streams of data. It is therefore required for a modern grid. To provide customer specific insights and recommendations, these operational systems require integration with SAP. SAP is the system of record for both customer site specific information (e.g., customer PV installation) and customer specific details (e.g. DER program participation, selected tariff, and billing). As covered in Exhibit F (*GMS System Architecture and Cyber Security*), these integrations are plentiful with respect to just SAP alone: SAP must be integrated with DEMS to associate customer DER with specific aggregated resources; MDMS is integrated with SAP for billing, the OMS is integrated with SAP to associate outages with specific customers. The ADMS investment will build upon prior investments in SAP, DEMS, and MDMS in a progression towards achieving a fully functional system of systems.

The ADMS near-term load forecasting for operational contingency calculation will also utilize SCADA and Field Device sensing data and advanced meter data provided by the Phase 1 MDMS. As the dynamic between electricity supply and demand becomes more dynamic with

[12] See Rule 2

increasing levels of DER, the ADMS near-term load forecasting capability becomes necessary for grid operators to start proactively identifying potential issues and taking action before customers are affected by an outage or voltage violation. This proactive approach will take time to develop as more advanced meters and distribution Field Devices are deployed and the grid operators receive more data as well as training and experience to utilize these new grid management tools.

The Companies plan to deploy the ADMS over three Releases, summarized below and shown in Figure 3, with each Release layering additional capabilities and more sophisticated controls while maintaining cyber security. Exhibit B (*Updated Project Justification with Business Case Support*) and Exhibit F (*GMS System Architecture and Cyber Security*) provide more detailed information about the ADMS components and related integrations.

- **Release 1 – Deploy Basic ADMS Features to all Companies and System-level DER Functions**
    - Basic OMS features – Replacement of the Hawaiian Electric OMS and installation of OMS on Maui Electric and Hawai‘i Electric Light, including outage tickets, outage call handling, training simulator, and mobile client;
    - Fault Location Analysis (FLA) – Ability to accept outage information from the Field Devices for the purposes of determining the location of an outage to customers;[13]
    - Basic DMS features[14] – Distribution SCADA for Hawaiian Electric, switch order handling for Hawaiian Electric, load forecasting, power flow analytics, and study mode;

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[13] Fault Location Analysis (FLA) was included in Release 2 in the original Grid Modernization Phase 2 ADMS application in September 2019. FLA was moved into Release 1 to improve fault analysis while utilizing distribution Field Device capabilities.

[14] Hawai‘i Electric Light’s and Maui Electric’s EMS contain distribution SCADA information down to the distribution circuit breaker. This will remain in the EMS.

- Basic SCADA features via Inter-Control Center Protocol (ICCP) – telemetry-only (no controls) via one-way integrations from existing EMS at each Company;
- Basic demand response (DR) and DER) features – to dispatch demand-side flexibility programs via the existing DEMS; and
- Integration with other key enterprise applications – Geographic Information System (GIS), SAP, Advanced Metering/MDMS, DEMS, and Asset Management Systems.

- **Release 2 – Deploy Additional ADMS Features and Localized DER Functions to All Companies**
  - Advanced features include distribution state estimation (DSE), fault location isolation and service restoration (FLISR), and primary connected, utility-controlled DER;
  - Implementation of Distribution SCADA for telemetry and control of distribution Field Devices and DERs on the distribution primary side;
  - Additional SCADA integrations with EMS to receive transmission state estimator values and pass controls to EMS-managed devices and resources; and
  - Ability to monitor and adjust the real or reactive power injection of large DER; and
  - Integration with wind and solar forecasting services from UL Renewables.
- ***Release 3 – Deploy Advanced DA and Optimize DER Features for All Companies***
  - Advanced DA integration includes volt-var optimization (VVO) and advanced protection equipment coordination schemes;
  - Advanced DER integration includes forward-looking contingency analysis, predictive DER scheduling, and load-shedding algorithms;
  - Additional integrations to field volt-var control devices, protection, and switching equipment; and
  - Enhanced integration to DEMS to enable status, availability, and control of all customer-sited DERs, including active loads, distributed grid-connected photovoltaic (“DGPV”) systems, battery controllers, and electric vehicle charging.

1. System Integration

The ADMS must be integrated with other enterprise systems to realize its full potential, as described in Exhibit B (*Updated Project Justification with Business Case Support*) and Exhibit F (*GMS System Architecture and Cyber Security*). The ADMS utilizes the GIS, grid connectivity model, and telemetered data from substation automation SCADA as well as distribution Field Devices to understand the current configuration of the grid and assess other possible configurations of the distribution system. The advanced meters will also utilize their sensing capabilities to notify the Companies when customers are experiencing an outage or abnormal voltage conditions. Integration is required with the DEMS to dispatch DER, Non-Wired Alternatives ("NWA"), and local grid services like reserve capacity, power quality, and highly surgical ancillary services. Additional system integrations include interfaces with: (a) the existing EMS on each island for coordination with transmission operations; (b) the SAP customer information and customer care system used by the call center; and (c) third-party wind and solar forecasting vendors.

The Commission previously approved the implementation of a DRMS, which will evolve into a DERMS through the Companies' implementation of the DEMS.[15] The ADMS will interface with the DEMS in order to dispatch customer-owned DER resources that participate in

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[15] See Docket No. 2015-0411, Decision and Order No. 34884, issued on October 18, 2017. The DEMS is the name of the product that was approved in the DRMS docket. As the Commission recognized with D&O 36476, the line between DR and DER is nuanced from a policy and program perspective. Similarly, the differentiation between the functions associated with the management software capabilities is nuanced. The industry terms of DRMS and DERMS do not comport neatly with the Companies' unique and industry-leading vision wherein customer-sited resources will be relied upon for routine grid operation.

customer energy options.[16] The DEMS will manage the customer- and aggregator-facing aspects of the available customer energy options, while the ADMS will manage the distribution system and dispatch DER as needed to meet grid needs. For example, as part of the Integrated Grid Planning ("IGP") process, the Companies are identifying areas where NWA could address capacity constraints across the system.[17] Once an NWA is implemented, the ADMS will monitor to determine when the dispatchable distributed resources (*e.g.*, Demand Response and/or Energy Storage) in those areas are needed to stay within the capacity rating of the infrastructure and coordinate with the DEMS to dispatch appropriately. Additionally, the data utilized for real-time grid operations will also provide distribution planners with increasing amounts of historical data in order to refine load forecasts, hosting capacity studies, and interconnection analyses for customers, and evaluate NWA in comparison with traditional infrastructure investments. Future cycles of IGP will utilize this data to refine planning analyses.[18]

Capacity ratings specify the physical limitations on the amount of electricity that flows through a component of the power system. If those limits are exceeded for a sustained period of time, it could lead to reliability and/or safety issues, such as conductor or transformer failure. The ADMS will be used to send a dispatch request to the DEMS, which will, in turn, relay that

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[16] The term "customer energy options" as utilized in this Supplement 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").

[17] See https://www hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/distribution-planning-and-grid-services-documents.

[18] The Companies continue to refine distribution planning processes with a goal to expedite and improve interconnection requests. These benefits are unlocked through data analytics and in conjunction with the Integrated Grid Planning proceedings. On December 4, 2019, EPRI provided an update to the Distribution Planning Working Group on probabilistic hosting capacity analyses that they are developing with the Companies.

command to the participating DER aggregator(s) and/or participating customers provide grid services in a way that decreases the capacity rating exceedances. Subsequent to dispatch, the GMS Phase 1 advanced meters will provide interval usage data through the MDMS, which in turn will provide it to the DEMS to perform the Measurement and Verification ("M&V") performance evaluation of the customer-owned resources and the aggregated DR/DER resource(s). This level of proactive equipment monitoring improves reliability providing value for both communities and customers with the opportunity to proactively identify and mitigate underlying issues that cause some of the unplanned outages that cause inconvenience and some economic impact to our customers,[19]

2. Training

The Companies have an established training system for grid operators utilizing existing systems such as the EMS and the OMS on O'ahu. Each position has minimum requirements of instructor-led classroom courses and structured on-the-job training before grid operators are allowed to perform their functions independently. Each position requires a minimum training time of one to two years before a system operator is fully proficient. In addition, each of the island utility grids have operated as independent grid operators, each with their own set of processes, rules, and training systems.

The ADMS is one of the foundational tools for grid operators, expanding from operating system–level substation automation SCADA devices to also having distribution automation for understanding more complex and more abundant paths of electricity flow at the distribution

[19] See Exhibit B Section IV.C.3. estimate of customer benefit calculated by the U.S. Department of Energy ("DOE") Interruption Cost Estimate (ICE) Calculator (https://icecalculator.com/)

level. In the case of Hawaiian Electric, which has an existing OMS, the grid operators will be required to learn additional features of the ADMS that come with DMS and the Advanced Applications of the ADMS. The Maui Electric and Hawai‘i Electric Light grid operators will be required to learn OMS, DMS, and Advanced Applications of the ADMS. Realizing the full value of an ADMS requires a tremendous amount of training. The Companies' desire is to approach the Project with a discipline to not only implement an ADMS but also gain efficiencies by standardizing processes among the Companies and establish a common look, feel, and operation of the ADMS for all three. As learned through the Hawaiian Electric OMS project, use of a training simulator is one of the most effective ways to train grid operators. The simulator places the operator in an environment where the system is not affected by their actions yet grid operators can visualize all of the inputs the ADMS will provide and understand how their decisions will be informed by the situational awareness provided when the ADMS goes live. Training and simulation combine to decrease the number of mistakes and shorten the learning curve for the grid operators. Section III.A of Exhibit B (*Updated Project Justification with Business Case Support*) provides additional details on the associated training for Grid Operators and system operations.

B. FIELD DEVICES DESCRIPTION

The Field Devices for targeted deployment and integration with the ADMS are:

- **Secondary VAR Controllers (SVCs) –** These devices use power electronics-based, fast-acting, decentralized shunt-VAR technology for voltage regulation. SVCs can also provide limited system monitoring capability, including outage and voltage notifications. Installed on the secondary side of a distribution transformer to address voltage issues downstream of the voltage regulating capabilities at the substations, SVCs help to ensure that voltage levels for all customers on the circuits are within tariff tolerances and have the potential to increase the hosting capacity of existing circuits.

- **Line Sensors –** Typically installed on parts of the distribution feeders, these devices provide granular power quality information on distribution system conditions.
- **Remote Fault Indicators (RFIs) –** Field Devices that sense fault current to help determine the source and location of the outage. The OMS assists Grid Operator coordination with field personnel to respond more quickly to the outage by more accurately locating the problem area and dispatching restoration crews so that they can begin the restoration of power.
- **Remote Intelligent Switch –** Utility pole mounted electro-mechanical switch that shifts load from one circuit to another or isolates sections of a circuit for maintenance and outage restoration. These devices have autonomous functions to isolate faulted sections of the grid and also interface with the ADMS to provide system operator visibility and control.
    - **Reclosers** – Some of these electro-mechanical devices, called reclosers, can react to a short circuit by interrupting electrical flow and automatically reconnecting the circuit topology a short time later. Reclosers function as circuit breakers on the circuit and are located throughout the distribution

system to prevent a temporary/momentary fault from causing an extended outage.

- **Smart Fuse** – Similar to reclosers, these devices are placed throughout the distribution system, replacing traditional fuses with smart devices that reduce truck rolls, maintenance cost, and the number of customers affected by prolonged outages. Smart fuses provide the reclosing and isolating capabilities of reclosers on lateral lines.

As detailed throughout this Supplement, this Project seeks to deploy Field Devices to enhance grid capabilities and flexibility in concert with the ADMS with the goal of enabling additional distributed and renewable energy resources. These devices improve the system's ability to safely and reliably monitor and manage the changing resource mix to the benefit of all customers. Whereas disturbances on the distribution grid have historically meant localized power disruptions, those events can cause system challenges given increased reliance on customer-sited generation to serve system load and to achieve RPS goals. The deployment of distribution automation Field Devices is a significant component in the coordinated effort to update the distribution grid with the capabilities required to efficiently utilize all grid-connected resources through a combination of grid-scale and distributed resources. In sum, the deployment of Field Devices leverages the full capability of the ADMS that ultimately enables customer options, enhances reliability and resilience for customers, and realizes operational efficiencies.

The Field Devices directly benefit customers in at least two ways; they: 1) monitor and, in the case of SVCs, mitigate voltage issues which occur as circuits approach hosting capacity; 2) enhance system reliability and resilience via new automation capabilities, such as reclosers and smart fuses that automatically determine if a fault is persistent and isolate the faulted section of a circuit. The ADMS receives this data and information thereby providing grid operators with situational awareness of the distribution system while utilizing the ADMS controls, distribution automation, and substation automation to mitigate issues, and more accurately dispatch field crews to grid locations that are having issues. This is an improvement over today when grid operators only have visibility to the substations with SCADA. More detail on customer benefits are included in Exhibit B (*Updated Project Justification with Business Case Support*).

The Companies have noted the need for increased situational awareness of the distribution system previously and have piloted technologies to assess the urgency of monitoring.[20] The results from the Distribution Circuit Monitoring Program show that with increasing DER, the distribution system is dynamic, resulting in variable power flows that are highly dependent on field conditions and localized conditions. Building from the lessons learned from the pilot deployment and voltage control plans at the substation-level, the Companies teamed with Siemens to develop a Field Device strategy that focuses on voltage management to improve the quality of service for our customers (See Exhibit K *Siemens Field Device Strategy*). The Field Device Strategy incorporates and attempts to optimize the deployment alongside other initiatives, including reliability-oriented investments, SCADA rollout plans, and advanced meter deployments.

Since the Grid Modernization Strategy and Phase 1 Application, the Companies have continued to strategically deploy limited numbers of Field Devices using existing capital

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[20] See Docket 2014-0192, *Proceeding to Investigate Distributed Energy Resource Policies.* Distribution Circuit Monitoring Program (DCMP) Plan, Filed March 9, 2017.

programs to address immediate needs for grid sensing, voltage controls, and reliability improvements while also assessing the capabilities for these devices. Some of the Field Devices that have already been deployed will also interface with the ADMS – although a subset of those that are capable will require enablement of the telecommunications capabilities to do so. In addition to providing immediate reliability benefits and helping the Companies' performance with the reliability PIMs, this approach has helped grid operators become familiar with the Field Device capabilities in advance of enabling the full capabilities of Field Devices through the ADMS interface.

Given the GMS deployment strategy targeting distribution automation Field Devices (*i.e.*, beyond the substation) for monitoring, control, and automation, these Field Devices will unlock new capabilities to remotely manage the distribution grid with geographic granularity and a level of precision that is not possible in the current system. The Companies have utilized and to deploy substation automation observation and control capabilities, with approximately 47% of substations outfitted with industry-standard substation automation SCADA capabilities.[21] The Companies plan to continue to incrementally retrofit non-SCADA substations with SCADA over time as part of the normal course of action in coordination with the grid modernization program but separate from the grid modernization funding mechanisms. The ADMS will interface with both substation automation SCADA as well as distribution automation Field Devices.

Distribution automation Field Devices enable greater visibility of outages and dynamic grid conditions on the distribution circuits, which are increasingly providing the interconnection

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[21] Substation automation devices and SCADA are outside the scope of Grid Modernization, but the ADMS will interface with SCADA and substation automation equipment.

for customer-sited DER. These Field Devices provide the tools to manage the grid through the ADMS such that all customers continue to experience the quality of service that they expect while enabling the integration of increasing levels of renewable and distributed resources in pursuit of Hawai‘i’s RPS goals.

The Companies’ timing for the installation of an ADMS with Field Device capabilities that build over time was chosen deliberately and is intended to maximize the value of both investments. The first release of the ADMS will take approximately two years to implement, as configuration and test procedures must ensure the reliability of this critical operational system, including integration with other enterprise systems to achieve the desired results. Exhibit B (*Updated Project Justification with Business Case Support*) outlines the urgency for the ADMS implementation, and the rapid, targeted deployment of the identified Field Devices.

The full capabilities of these Field Devices cannot be attained without the management software (ADMS) in place. Conversely, the ADMS cannot attain its full potential without the Field Devices. The interrelation and support of these investments is further discussed in Exhibit A (*Grid Modernization Strategy Working Plan*) and Exhibit B (*Updated Project Justification with Business Case Support*).

1. <u>Proportional and Flexible Field Device Strategy</u>

As discussed more fully in the Project Justification section and in Exhibit A (*Grid Modernization Strategy Working Plan),* the Project is intended to support customer DER interconnections while also addressing the existing and emerging power quality (voltage) and reliability challenges today. As articulated in the GMS, additional investment in these types of technologies will continue to be needed after the Grid Modernization initiative as needs arise:

"Ongoing foundational technology investments in sensing and measurement, communications, and distribution automation will become the new business as usual and continue to be proportionally deployed in subsequent phases based on prioritized need identified through the [IGP] process."[22] The intent of the Grid Modernization investments includes implementing the systems (MDMS, ADMS, telecommunications) to enable modern devices (advanced meters and Field Devices) and kick-start the deployment of those devices "as needed, where needed" to support customer energy options and progression toward the RPS goals.

The Field Device quantities and proportions contained herein stay within the Commission-approved GMS conceptual budget and reflect lessons learned since then, but more Field Devices will be needed both in the long term and in the near term. The distribution Field Device quantities and strategy here represent roughly 45% of the needs identified. Consistent with the GMS plan to kick-start Field Device deployments, and because of rate impact sensitivity and resource constraints that may have affected our ability to execute a larger project, the current Field Device strategy represents an actionable and executable near-term plan.

A programmatic approach to Field Device deployments may identify new efficiencies in deployment and allow for flexibility to meet grid needs as they arise. The strategy is to meet customer needs today and lay a groundwork for tomorrow, adjusting course over the near and long term to meet evolving customer needs and expectations. The Companies expect to become more efficient at both the deployment and operation of these new technologies and systems over time as experience is gained and the number of devices provide more data and insight. The cost

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[22] See GMS at 103.

estimates for Field Device deployment incorporated a "learning curve" relative to the documented time it currently takes to engineer, test, and install Field Devices with the expectation that with each device deployment the work would be performed more efficiently than the prior deployment. The resultant unit costs to install each device, therefore, decline over the 5-year period.

The Companies need flexibility in the Field Device deployment to balance an evolving set of interests, factors and objectives, including DER integration, customer expectations, reliability, resilience, and aging infrastructure. The five-year Field Device deployment plan is based on studies and analysis reflecting today's needs (See Exhibit K *Siemens Field Device Strategy*). However, we expect the plan to evolve during the five-year period. For example, the number of RFIs may decrease if the Companies find that the other Field Devices provide a similar level of outage notification and an SVC could provide not only outage notification but also VAR control. Therefore, the Companies need flexibility in the deployment of Field Devices to refine the plan to address emerging challenges with reliability, resilience, and power quality while being efficient with resources adjusting to meet customer expectations.

C. PROJECT SCHEDULE

1. ADMS Schedule

The entire ADMS deployment spans three releases or phases (described above) and will last approximately four and a half years, as depicted in Figure 3.

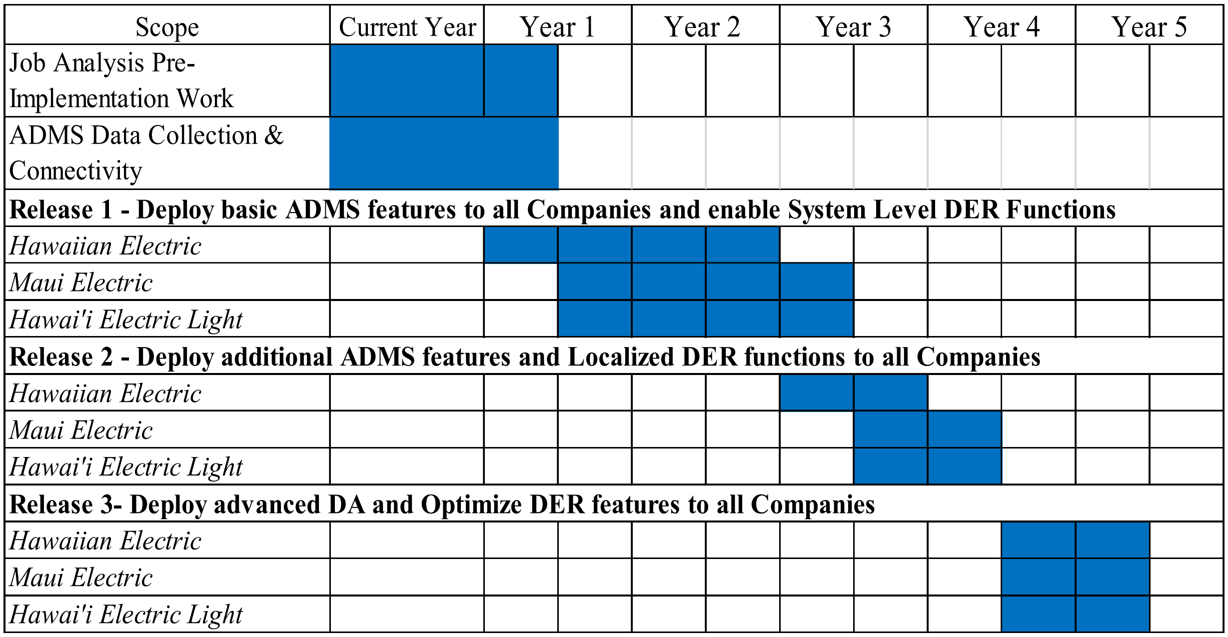

Figure 3

2. <u>Field Device Schedule</u>

The Tables below provide the estimated schedule for Field Device deployment as part of GMS Phase 2. The schedule is subject to changes needed to meet future customer and grid requirements.

Hawaiian Electric Companies	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total**
Recloser	2	6	10	12	9	39
Smart Fuse	22	66	110	132	110	440
RFI	12	36	60	71	59	238
SVC	32	96	160	192	161	641
Line Sensor	83	250	417	500	416	1666
Grand Total	151	454	757	907	755	3024

Table 2

Hawaiian Electric	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total**
Recloser	1	4	6	7	5	**23**
Smart Fuse	16	47	79	94	80	**316**
RFI	0	2	3	4	4	**13**
SVC	17	50	84	101	85	**337**
Line Sensor	55	165	273	328	272	**1093**
Sub-Total	**89**	**268**	**445**	**534**	**446**	**1782**

Table 3

Hawai`i Electric Light	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total**
Recloser	0	1	2	3	2	**8**
Smart Fuse	1	5	7	9	7	**29**
RFI	10	29	48	57	47	**191**
SVC	0	0	0	0	0	**0**
Line Sensor	19	57	96	115	95	**382**
Sub-Total	**30**	**92**	**153**	**184**	**151**	**610**

Table 4

Maui Electric	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total**
Recloser	1	1	2	2	2	**8**
Smart Fuse	5	14	24	29	23	**95**
RFI	2	5	9	10	8	**34**
SVC	15	46	76	91	76	**304**
Line Sensor	9	28	48	57	49	**191**
Sub-Total	**32**	**94**	**159**	**189**	**158**	**632**

Table 5

VIII. PROJECT JUSTIFICATION

The ADMS and Field Devices are needed in order to monitor and manage the islands' distribution grids with increasing variable and intermittent renewable resources throughout the system, including distributed generation at customer locations, while improving reliability and maintaining power quality of the distribution grids. This will result in more customers interconnecting DER into the grid, ensuring that grid is more available so existing DER customers can maximize the benefit from their DER investments, and allow customers to participate in future energy programs. Additional information on the benefits of the combination of ADMS and Field Devices is found in Exhibit B (*Updated Project Justification with Business Case Support*). The timing of this Supplement is the result of multiple analyses, pilots, and studies to gain insight into the types, costs, and quantities of distribution automation Field Devices to support reliability, resiliency, and power quality (voltage).

This Supplement is coordinated with the GMS implementation as a whole as well as other ongoing activities across the Companies. That coordination will continue through deployment of both components in order to optimize ADMS implementation within the broader IT and OT ecosystem, and to optimize the quantity and placement of Field Devices to support power quality (voltage), reliability, resiliency (including wildfire mitigation), and power quality (voltage).

Implementation of the ADMS and deployment of the Field Devices is also crucial to support the DER from Docket No. 2019-0323, Community-Based Renewable Energy ("CBRE"),[23] and Electrification of Transportation initiatives.[24]

To date, Field Devices have been deployed to mitigate specific issues. For example, reclosers have been installed (largely without communications) in areas with reliability issues where the recloser serves to sectionalize a circuit so that fewer customers experience service interruptions for faults downstream from the recloser and re-establishes service automatically after a momentary fault rather than a crew needing to be dispatched to investigate and restore

[23] See Docket No. 2015-0389
[24] See Docket No. 2016-0168

service. Temporary fault conditions are often caused by vegetation encroachment on the power lines, and with more sensing and analytics of the resulting data, the information on momentary faults can result in directing tree trimming crews to specific areas that are experiencing multiple events.

This Project will enable Field Device deployment to be consolidated under a single program and thus allow greater efficiencies to be realized. Unlike prior deployments, the Project Field Device deployments: 1) will provide distribution automation sensing and control capabilities for the ADMS; 2) their placement will be optimized based on the multiple capabilities embedded within some of the devices (e.g., reclosers provide switching as well as sensing); and 3) they will utilize the telecommunications network to provide situational awareness to grid operators in combination with the sensing and controls being deployed with the advanced meters. The challenge of optimizing the deployment of these devices is articulated in the pages that follow and align with the GMS vision to ensure that the multiple capabilities of each device are leveraged, rather than the continued deployment of devices driven by a single purpose.

The Companies approach remains aligned with the U.S Department of Energy ("DOE") Modern Distribution Grid Project and the next generation distribution system platform and applications ("DSPx"). The Figure below is a reproduction of GMS Figure 4 "DOE DSPx Next Generation Distribution System Platform" and originally appears in the DSPx documentation.

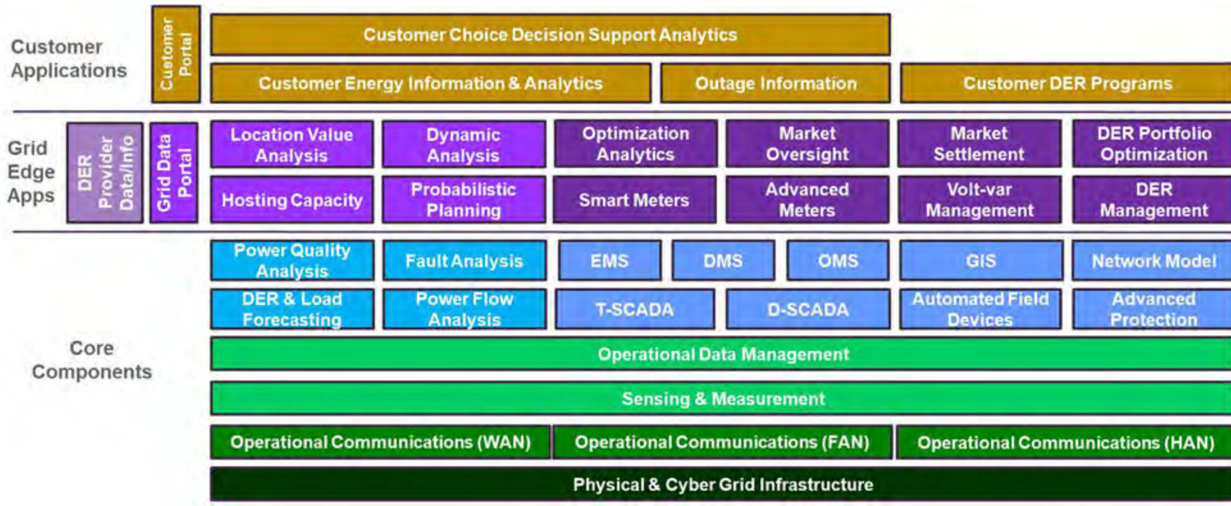

Figure 4

GMS Figure 5 (see the Figure below) depicted the *Current Status of the Companies' Customer-Facing and Advanced Grid Technologies* in 2017. The gradient filling on the systems and capabilities reflect the 2017 capabilities as illustrated in GMS Figure 9.

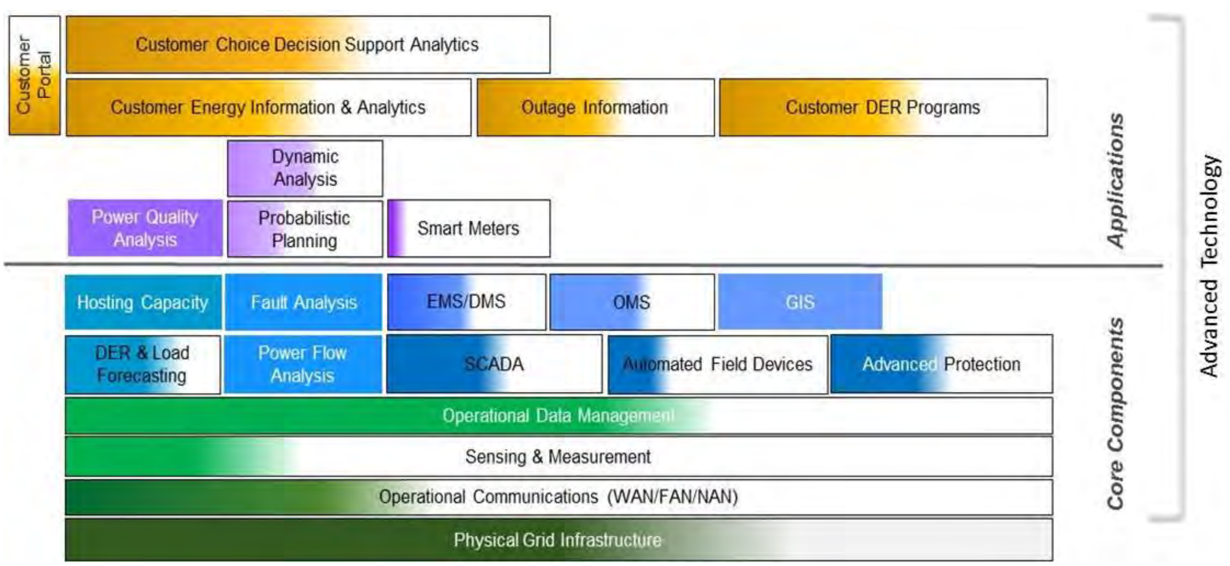

Figure 5

Grid Modernization investments are sequenced to incrementally enable a modern grid platform to support deployment of grid-scale renewable energy and storage as well as customer

DER integration. Figure 6 depicts how the DRMS/DEMS project in combination with the Grid Modernization investments have focused on filling the gaps identified in 2017 (illustrated in **Error! Reference source not found.**) to build a modern distribution platform as articulated by the DOE DSPx, envisioned in the GMS, and approved by the Commission.[25] The outline shading illustrates the DRMS/DEMS, Grid Mod Phase 1 & Phase 2 contributions to building a "next generation" distribution system platform and dashed lines are partially addressed (but the scope is larger than just grid modernization). Without the Grid Modernization Phase 2 investments in the ADMS and Field Devices, the capabilities needed to monitor and manage the distribution grid to support customer DER will be greatly diminished and the ability to achieve the RPS goals in a strategic, well-planned manner is questionable.

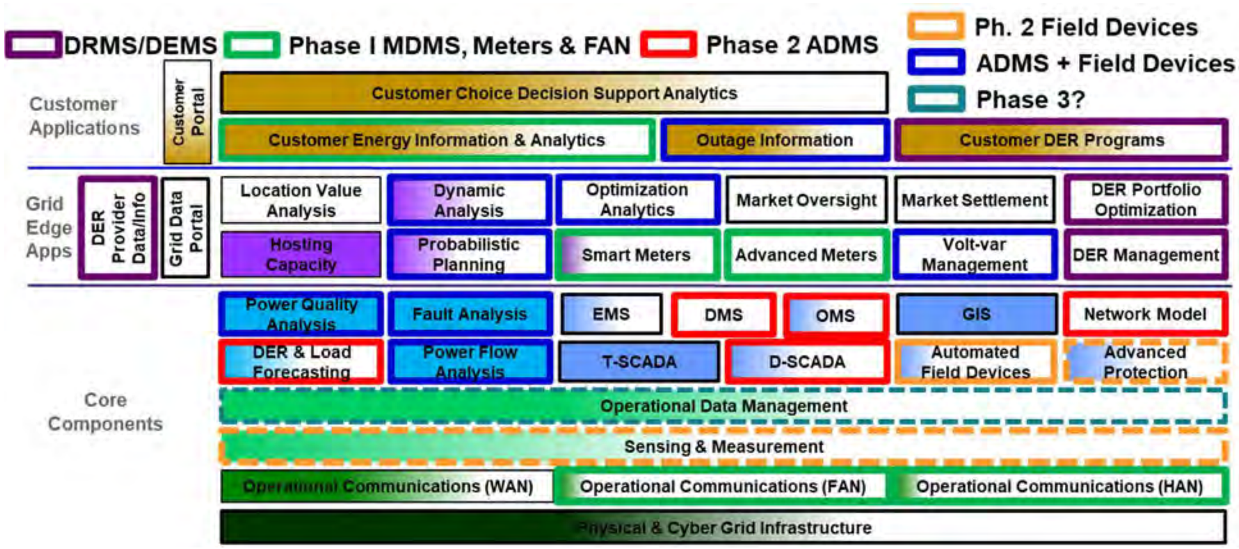

Figure 6

[25] See Docket No. 2017-0226 D&O 35268

For the DSPx "core components" related to the ADMS and Field Devices, the **DMS** and **OMS** are core modules of the ADMS. In order for the ADMS to accurately monitor and control the distribution grid, it requires the **GIS** and **network model** to have the context of geographic and electrical topology. The ADMS will perform **fault analysis**, **power flow analysis** and either utilize distribution SCADA (**D-SCADA)** data or be the system of record for the **D-SCADA**.[26] The **automated Field Devices** are the subject of this application and the data gathered from the distribution automation Field Devices in combination with substation automation and advanced meter data will inform both **DER & load forecasting** and **power quality analysis**.[27]

For the DSPx Grid Edge Apps related to the ADMS and Field Devices, **Volt-VAR management** is needed to maintain power quality on a distribution system with high levels of DER. The **dynamic analysis** becomes necessary for the ADMS to monitor and manage the dynamic grid conditions with DER and the **probabilistic planning** and **optimization analytics** will provide the Field Device and substation automation data to distribution planning to incorporate into future iterations of the IGP to further refine grid needs in pursuit of RPS goals.

The customer applications have been a focus for Grid Modernization as the GMS was developed with customer input.[28] Grid Modernization Phase 1 is implementing a **customer energy portal** to provide customer energy information and analytics. For Phase 2, the focus is on improving the outage information and maps currently available to customers with the outage data from advanced metering and Field Devices and the coordinated outage response enabled by the

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[26] Hawaiʻi Electric Light's and Maui Electric's EMS contain distribution SCADA information down to the distribution circuit breaker. This will remain in the EMS

[27] **Bold** font intended to associate with the DSPx descriptions in Figure

[28] See GMS Appendix B: Ward Research Electric Grid Modernization Study

ADMS.[29] As Field Devices and advanced meters provide more granular outage information, Hawai`i Electric Light and Maui Electric will begin utilizing an OMS for the first time, and the estimated time to restoration ("ETR") will gradually become more refined as outage data is analyzed.

These benefits are consistent with the guiding principles, regulatory goals, and priority outcomes established by the Commission under the new Performance-Based Regulation ("PBR") framework.[30] Please see Exhibit B (*Updated Project Justification with Business Case Support)* for a more detailed description of the benefits associated with this Project.

A. ADMS JUSTIFICATION – CONTROLLING THE SYSTEM

Managing the existing and future electrical grid requires new systems in the control room to coordinate a reliable and optimized integration of distributed, variable, and renewable resources. As stated earlier, the Companies are managing the bulk power system without visibility into or control over the vast majority of distributed resources or the operating state of the distribution network. Existing tools are limited, and manual processes are used to operate a distribution system that is experiencing pioneering levels of renewable penetration and widespread reverse power flows. These distributed resources have a substantial impact on both the distribution system and the bulk grid, and the lack of visibility and control over such a major component of the total grid energy is risky and unsustainable. The ADMS will provide the grid operators with the visibility and control to operate a modern grid. The benefits of an ADMS can be summarized in three broad categories:

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[29] See https://www.hawaiianelectric.com/safety-and-outages/power-outages

[30] See Docket No. 2018-0088, D&O No. 36326, issued on May 23, 2019.

1. Enable customer energy options while advancing clean energy goals – An ADMS is critical to sustaining and continuing the growth of DER. The ADMS will provide operational visibility, monitoring, and analytics that can facilitate safe, reliable operation of a large and varying number of energy sources on the distribution system, enabling customer choice while maintaining or improving grid resilience. The ADMS will be the coordination hub of a distributed, layered architecture approach, as presented in Figure 5 from the GMS.[31] The ADMS is an integral part of the overall Grid Modernization Strategy: It is the central control system that provides grid edge[32] visibility, control, and optimization as well as monitoring, command, and control of Field Devices. Without an ADMS, the distribution grid capability to support customer energy options will be limited and the respective benefits of these options will not be fully realized.

2. Reduce outages and improve customer communications – The primary purpose and benefit for implementing the OMS module of an ADMS is to reduce outage restoration time, as measured by the System Average Interruption Duration Index ("SAIDI") and Customer Average Interruption Duration Index ("CAIDI").[33] Improvements in SAIDI and CAIDI are to be achieved by improving the ability of the control room operator to identify the location and causes of faults, prioritizing outages

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[31] GMS, at 20.

[32] "Grid edge" refers to the seam where the distribution system meets the customer premise. It is a broad term intended to capture the Companies' most distributed assets and customer resources.

[33] Note that as more sensing and reclosing capabilities are deployed, it is likely that the Momentary Average Interruption Frequency Index ("MAIFI") will initially increase, but that data can then be utilized to identify and mitigate the causes of momentary interruptions (e.g., vegetation management)

based on customers affected, and optimizing the dispatch of field technicians. By implementing an ADMS, and augmenting the OMS capabilities with FLISR, the Companies can better meet customer, local media, and government expectations of increased communication and detailed operations information during both normal and emergency situations. Recent years have included frequent emergency incident response events due to severe weather and volcanic eruption impacts, requiring the entire System Operations and Planning divisions to participate in coordinated emergency response and to develop and update communications plans for resilience and restoration.[34] An ADMS will enable grid operators to better coordinate emergency responses and keep communities informed.

3. **Enhance operational resiliency and efficiency** – The ADMS will provide grid operators with improved visibility, control, and optimization of contingency situations and protection schemes. The ADMS Study and Powerflow functionality allows grid operators to analyze distribution grid edge voltage support and to short-circuit current availability while supporting analysis of the impact of potential events. ADMS can also provide a platform to integrate grid-tied storage batteries which can then be incorporated into restoration and recovery plans. However, this functionality is still developing; thus, further investigation is underway to evaluate what platforms to utilize and how they would integrate with the DEMS. In general, the ADMS will support complex

[34] See the IGP Resilience Working Group (RWG) report and supporting documentation: https://www hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/resilience-documents

contingency response, as well as state estimation analysis to include consideration of the distribution systems, since smaller DER assets increasingly provide a majority of total grid energy. Additionally, the ADMS solution will improve resiliency and analysis following disruptions by enhancing situational awareness and assisting in restoration triage to recover from events faster.

These benefits are also consistent with the guiding principles, regulatory goals, and priority outcomes established for the new PBR framework.[35] Please see Exhibit B (*Updated Project Justification with Business Case Support*) for a more detailed description of the benefits associated with this Project.

B. FIELD DEVICES JUSTIFICATION - BUILDING ON THE EARLIER APPLICATIONS

The deployment and integration of a variety of Field Devices are aimed at providing the tools for greater visibility, control, and optimization of the distribution system through the ADMS for more reliable operations of a two-way grid with increasing DER. The Figure below shows the phases of technologies identified in the Grid Modernization Strategy. The Figure, which originally appeared in the GMS as Figure 19, has been updated to show Phase 1 and Phase 2 Components.

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[35] See Docket No. 2018-0088, Decision and Order No. 36326, issued on May 23, 2019.

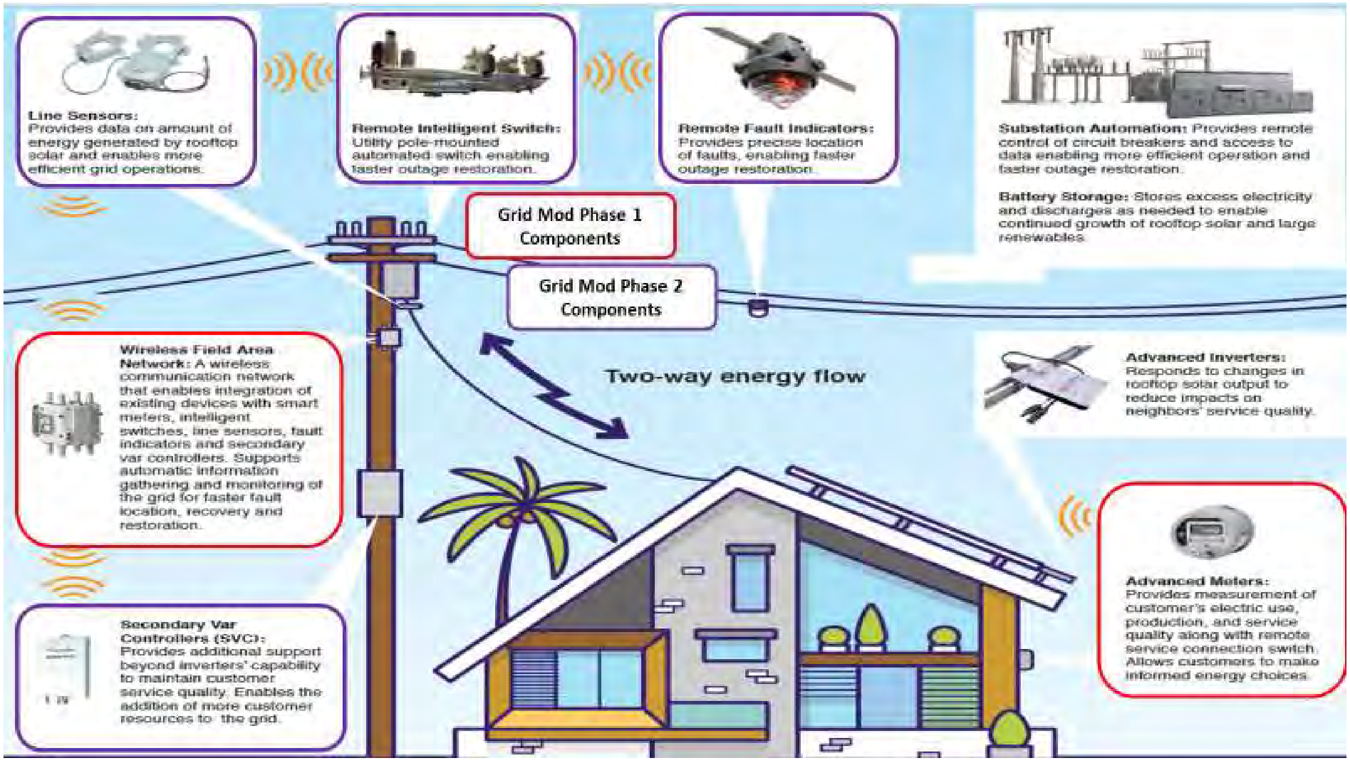

Figure 7

1. Building on Phase 1 Investments

The Field Device monitoring and control capabilities discussed in this Application will supplement the monitoring and control capabilities of the advanced metering approved in the Phase 1 application, with the advanced meters providing outage notifications to improve the timeliness of outage identification and response, as well as voltage notifications to alert grid operators when a customer's power is approaching the allowable limits of American National Standard Institute (ANSI) voltage ratings.[36,37] Meters will also provide 5-minute interval meter

[36] See ANSI C84.1-2020 https://www.nema.org/Standards/view/American-National-Standard-for-Electric-Power-Systems-and-Equipment-Voltage-Ratings

[37] Note that the voltage notifications are configurable and may be adjusted as the Companies assess the efficacy and usefulness of the initial configuration.

data including Active Energy (kWh delivered and received), Reactive Power (kVARh (volt-ampere reactive) delivered and received), Voltage (V average, minimum, and maximum for residential and small commercial customers or average voltage per phase and voltage sag/swell for larger 3-phase commercial customers).[38]

As articulated in the Grid Modernization Phase 1 Application Exhibit G – Telecommunications Network Considerations, the primary Field Area Network ("FAN") telecommunication paths for advanced metering and Field Devices include mesh networking, cellular LTE, and utilizing the substation WAN where appropriate.[39]

2. Deployment Functionality

These Field Devices provide three primary functions for customers and grid operators.

- **Voltage Management:** Customer DER can fluctuate the voltage profile of the distribution system in ways that make new equipment necessary to effectively (1) monitor voltage with advanced meters and line sensors and (2) maintain the quality of service with ADMS VVO using substation automation and SVCs. The SVCs provide active voltage management to improve circuit hosting capacity.[40]

- **Situational Awareness:** Data and measurements to know what is happening on the distribution grid to both proactively prevent problems and more efficiently and effectively respond when there are problems.

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[38] Due to bandwidth constraints, the PLX meters serving more remote areas of the service territories have 15-minute interval data and have a smaller data set primarily to support tariff provisions for billing and customer energy options and outage notifications.

[39] See Docket No. 2018-0141. Advanced meters also utilize power line carrier where neither mesh nor cellular LTE is viable.

[40] See *Exhibit K Siemens Field Device Strategy*

- **Outage Management**: Sensing and monitoring to identifying outages, automatically reclosing to restore power from momentary fault conditions, notifying grid operators of persistent fault conditions, organizing outage management and response with the OMS, and supplementing OMS capabilities with ADMS FLISR.

Coupled with these primary functions are equally complimentary functions that can help the Companies to better manage a modern grid. These complimentary functions allow for system reconfiguration to optimize power flow, improve system loading to minimize overloaded conditions which can accelerate asset aging, and generally improve the quality of service available to customers.

The original September 2019 Phase 2 ADMS Application included Exhibit F *(GMS System Architecture and Cyber Security for Grid Modernization),* which articulated the dependency of the ADMS on other enterprise and grid modernization systems, customer resources, and Field Devices to accomplish the capabilities available. The Commission recognized the interdependency of ADMS and Field Devices in suspending the original Application until the submittal of this Supplement. The original Application identified use cases describing the capabilities that the ADMS will provide to enhance reliability and maintain power quality while supporting the RPS goals.

The distribution automation Field Devices are necessary and/or enhance those use cases to utilize the ADMS functionality and achieve the ADMS benefits described. **Error! Reference source not found.**6, below, identifies the ADMS use cases where Field Devices are either required, enhance the functionality, or support the end goal. In many instances, the sensing capabilities of the Field Device result in support for a use case even if the primary use of the Field Device is not related to the use case. The Field Device enhances the ADMS use case if the additional sensing, control or automation capabilities improve use case execution relative to the use case being performed without the Field Device. For example, the top three use cases are related to SCADA and substation automation. Because the Field Devices are distribution automation rather than substation automation devices, they are not required for these SCADA use cases; however, the sensing capabilities of the Field Devices provide more data and precision through situational awareness of the distribution system, which either enhances or supports the use cases.

R = Required E = Enhance S= Support	Line Sensors	Remote Fault Indicator	Remote Intelligent Switch	Secondary VAR Controller	Advanced Meter
Use Case 1 – SCADA Events and Alarming	E	E	E	E	
Use Case 2 – SCADA Control			S	S	
Use Case 3 – SCADA Control System Updates	S	S	S	S	
Use Case 4 – Outage Management	E	E	E	S	S
Use Case 5 – Detect Restoration Issues	E	E	E	E	S
Use Case 6 – Switching Management	E	E	E		
Use Case 7 – Fault Location Analysis	R	R	R	E	E
Use Case 8 – Fault Location Isolation & Service Restoration ("FLISR")	E	E	R	S	S
Use Case 9 – State Estimation	E		E	E	S
Use Case 10 – Powerflow Studies	E		E	E	
Use Case 11 – Volt/VAR Optimization	R		S	R	E
Use Case 12 – Load Management	E				R
Use Case 13 – Forecasting	E		S	S	E
Use Case 14 – Dynamic Relay/Protection Settings	E		E	E	
Use Case 15 – EMS Coordination	S		S	S	S
Use Case 16 – GIS Updates	S	S	S	S	S
Use Case 19 – Asset Management Coordination	S	S	S	S	S

Table 6

3. Optimizing Deployment to Achieve the Desired Benefits

The placement of sensing devices will be determined by operational and planning requirements. Placement criteria and optimization algorithm for sensor placement and prioritization can quickly get complicated, given the variety of potential sensor placement locations, sensor types, and use cases utilizing the data. Optimizing device placement is further complicated by considering (1) the beneficial voltage notifications and monitoring capabilities provided by the Phase 1 advanced metering, and (2) the need to optimize for outage and system flexibility.

Therefore, because sensors are not single-use devices and can support a variety of use cases (See Table 2), the placement of sensors will not be driven by a single priority (*e.g.,* situational awareness). Instead, decisions on sensor placement will be guided to enable cumulative benefits from Field Device deployments. Observability investments will be prioritized to inform situational awareness, operational flexibility, and planning in the near term followed by a more granular state estimation in the longer term. While operational awareness/flexibility and granular state estimation are the near- and long-term priorities, other needs may arise as intermediate steps. Figure 8 below outlines how different technologies may be aligned to not only provide sensing capabilities (center square in the figure) but also voltage regulation, fault location, protection, and/or service restoration. The figure has been adapted from EnerNex work with multiple other utilities in development of their line sensing and Field Device strategies.

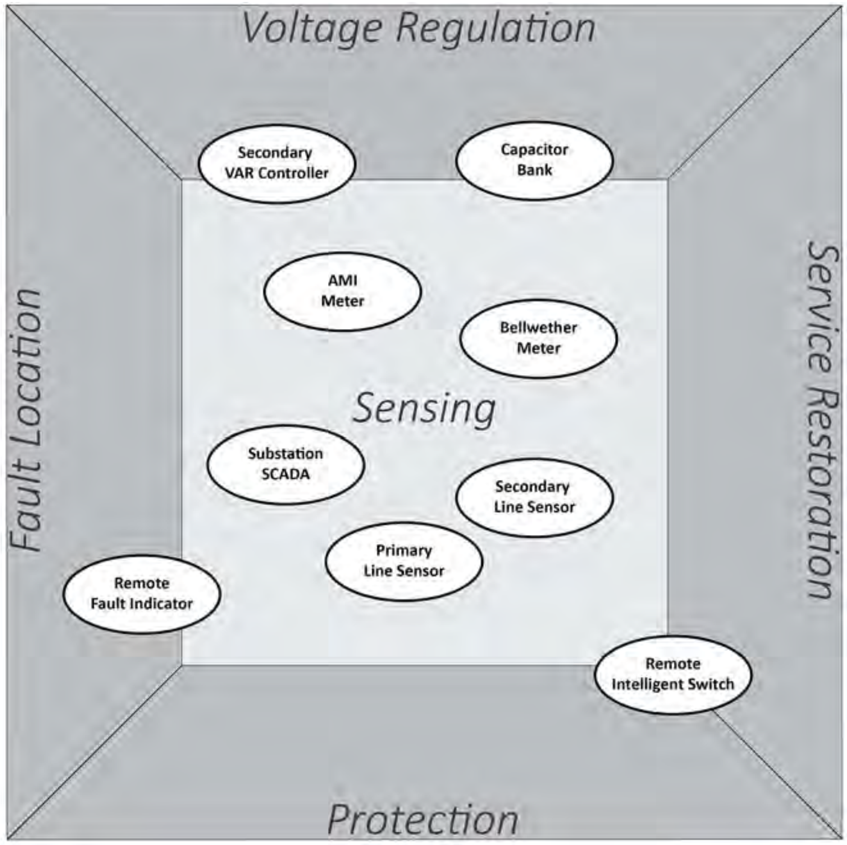

Figure 8

Generally, the Companies will be considering these complex themes and future needs in planning, coordinating, and prioritizing the Field Device placement strategies for prioritized deployment areas. Placing sensors everywhere will be helpful, but a prioritized, logical, proportional, and sequential deployment plan based on grid and customer needs aligns with the GMS approach of "as needed where needed."

The Companies expect that the deployment plan for the Phase 2 Field Devices may be the same or they may differ from those targeted for advanced metering. Where synergies exist, the Companies will coordinate activities to make the best use of such efficiencies. Field Device deployment will also be opportunistic. For example, devices can be deployed to a specific area if needed in combination with other work being done to the distribution system in that area. This approach for efficient work management has the potential to reduce the installation cost for the Field Devices, considering that the labor cost for planning, engineering, testing and deployment comprise the majority of the deployment cost.

C. RELATED PROGRAMS AND INITIATIVES

Since the time that the Companies filed their GMS and initial IGP Workplan,[41] the number of interrelated dockets, programs, and proceedings has increased. The related programs and activities have included for example executing the Stage 2 dispatchable and renewable generation procurement,[42] executing a "soft launch" procurement of non-wired alternatives,[43] implementing the DEMS while launching the customer energy option programs approved by the Commission,[44] exploring advanced rate design,[45] pursuing performance-based regulation,[46] and

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[41] See Docket No. 2018-0165, *Hawaiian Electric Companies' Integrated Grid Planning Report*, filed on July 13, 2018 ("IGP Report"). In addition, the Companies filed their IGP Workplan in Docket No. 2018-0165 on December 14, 2018. The Commission accepted the IGP Workplan via Order No. 36218 *Accepting the IGP Workplan and Providing Guidance*, issued on March 14, 2019. And the updated IGP workplan filed on January 19, 2021 and related Commission Order 37604 Establishing a Procedural Schedule for the First Review Point.

[42] See Docket No. 2017-0352, *Hawaiian Electric Companies' Final Stage 2; Renewable, Battery Storage and Grid Services RFPs*, filed on August 22, 2019.

[43] See Integrated Grid Planning ("IGP") Distribution Planning & Grid Services Working Group https://www hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/distribution-planning-and-grid-services-documents

[44] See Docket No. 2015-0411, Application For Approval To Defer Certain Computer Software Development Costs For A Demand Response Management System, To Accumulate An Allowance For Funds Used During Construction, Etc., filed on December 30, 2015. The DEMS is the name of the product that was approved in the Demand Response Management System ("DRMS") docket.

[45] See Docket No. 2018-0141 - Advanced Rate Design Strategy; and Data Access & Privacy Policy, filed September 25, 2019, and Docket No. 2019-0323. Instituting A Proceeding To Investigate Distributed Energy Resource Policies Pertaining to the Hawaiian Electric Companies.

[46] See Docket No. 2018-0088, Instituting A Proceeding To Investigate Performance-Based Regulation, opened by the Commission on April 18, 2018, via D&O No. 35411.

implementing the Phase 1 GMS deployment of advanced meters and FAN while installing an MDMS.[47]

The Companies have also begun to execute their IGP approach to harmonize the resource, transmission, and distribution planning processes by integrating information and alternatives from all sources and levels.[48] The IGP's updated workplan and first review point for forecasting and modeling was filed January 21, 2021.[49] Consistent with this methodology and the Commission's acceptance of the Companies' *PSIP Update Report: December 2016*,[50] the Companies' IGP provides a more detailed planning framework, the output of which will help identify future priorities for grid investment and modernization. A significant amount of time for IGP is spent on developing forecasts, assumptions, and models in order to plan for the resources and infrastructure needed to support the RPS goals. The data gathered from advanced meters, distribution automation Field Devices, and substation automation SCADA will provide a more robust data set to gain additional insight for forecasts, assumptions, and models to inform future IGP cycles.

IX. CYBER SECURITY

Hawaiian Electric's cyber security program is a comprehensive risk-based program, tailored to address our unique risk profile as an island utility with five separate electrical grids.

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[47] See Docket No. 2018-0141, Application 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, Etc., filed on June 21, 2018.

[48] See *Planning Hawai'i's Grid for Future Generations*, filed on March 1, 2018 in Docket No. 2017-0226, and Integrated Grid Planning Workplan, filed on December 14, 2018, in Docket No. 2018-0165 – available at http://www.hawaiianelectric.com/igp.

[49] See Docket No. 2018-0165, Hawaiian Electric Companies Updated IGP Workplan & Review Point

[50] See Docket No. 2014-0183, D&O No. 34696, issued on July 14, 2017.

The program is aligned to the National Institute of Standards and Technology's Cyber Security Framework (NIST-CSF) and other NIST standards, intended to effectively manage risk to critical infrastructure and adapt to evolving technologies, inherent vulnerabilities, and emerging threats. The Companies apply a defense-in-depth approach across people, process, and technology to ensure that our networks, devices, and data are protected by multiple layers of security controls. As described in Exhibit F (*GMS System Architecture and Cyber Security*), the layers include a wide variety of technologies and methods across the five dimensions of the NIST framework, including physical and logical segmentation of critical control systems, multi-level access controls, strong authentication mechanisms, intrusion detection sensors, and cryptographic systems, along with robust incident response plans.

The Companies recognize the increased risk associated with the introduction of grid modernization technologies. The deployment of numerous DER and Field Devices will expose more points of access on the grid, each of which represents a potential vulnerability that can be exploited. Therefore, systems such as the MDMS, DEMS, and ADMS will be deployed with comprehensive cyber security measures built into the overall architecture of the systems and integrated into operational processes and procedures. Significant foundational investments in information, communications, and operational systems are in progress and will continue over time in order to support the secure communication channels and secure data repositories for operational data generated by distribution-level Field Devices.

The cyber security framework provides a robust mechanism for the Companies to effectively implement these comprehensive cyber security measures in a manner that is consistent with industry-standard best practices for risk management. As the grid technology footprint expands and evolves over time, our implementation of security controls will also adapt and evolve, commensurate with risk to the grid. Finally, it is understood that many of the DERs currently in our system – as well as those expected to be added in the future – are owned and operated by third party entities (e.g., solar inverter vendors). We anticipate that these entities will make the necessary commitments to implement a comparable framework and program for cyber security risk management. The Companies support and encourage ongoing collaboration with third party grid participants to promote a holistic approach to grid security. See Exhibit F (*GMS System Architecture and Cyber Security*) for additional discussion.

X. FUTURE PHASES, PROGRAMS, AND INITIATIVES

Beyond Phase 1 and this proposed Phase 2, additional capabilities will be required to execute the complete vision articulated in the GMS. The table below is a copy of the GMS Table 7 *Conceptual Near-Term Deployment of Enterprise Systems and Field Deployments by Operating Company* with a new first column indicating the phase associated with each of the technologies identified in the GMS. The data management, Network Operation Center ("NOC"), and Distribution Operation Center ("DOC") are the items identified in the GMS that have not yet been addressed in Phase 1 or Phase 2. The existing operation centers will be going through upgrades as part of the ADMS implementation and other improvements have been pursued outside of GMS.

GMS Phase	Technology	Enterprise System	Hawaiian Electric	Hawai'i Electric Light	Maui Electric	C-E Method
1	**Advanced Meters**		92,000	200	52,000	Policy
1	**Head End & MDMS**	1				Policy

GMS Phase	Technology	Enterprise System	Hawaiian Electric	Hawai'i Electric Light	Maui Electric	C-E Method
2	**RFI**	1	1,300	500	400	SS&C
2	**Grid 20/20**		3,200	1,100	900	Policy
2	**Intelligent Switches**		220	75	60	SS&C
1	**Telecom Mesh Devices**		230	50	130	SS&C
2	**Secondary VAR Controllers**		1600	600	400	Policy
2-3	**Operational Analytics**	1				SS&C
2	**DMS**	1				SS&C
2	**OMS**	1				SS&C
2	**VVO**	1				Policy
2-3	**Data Management**	1				Policy
3	**NOC**	1				SS&C
3	**DOC**		1	1	1	SS&C

Table 7

Both the MDMS and ADMS include analytics and reporting capabilities to provide insight for distribution system operation, engineering, and planning. The analytics and reporting set the foundation for improved asset management capabilities, including condition-based monitoring and proactive approaches aimed at upgrading assets before they fail and cause outages. Condition-based monitoring is not just limited to asset management; the insights gained from advanced meters and Field Devices will also help the Companies to identify when customers experience momentary outages potentially caused by vegetation contact with power lines. Analysis of outage notifications will allow the Companies to target tree trimming in areas where it is needed before overgrown vegetation can cause extended outages.

Data repositories / historians for the MDMS and ADMS were identified as potential elements for a future Phase 3 application but are now included as part of this Phase 2 application because MDMS go-live results in an immediate need for a data repository / historian solution. The data repository / historian provides access to historical data to perform engineering analysis, system planning, load forecasting, and other analytics using existing tools. However, it is possible that an additional analytics engine or tools will be needed to provide additional insights, but identification of that need will depend upon setting up and utilizing the MDMS, ADMS, and data historian with existing planning and analytics tools to identify any gaps. The data historian solution is described further in Exhibit B Section II.C.3.

The analytics and data needs result from shifts in the makeup of the physical system. Analysis that could once focus solely on a given part of the system must now consider implications on other parts. Rather than create additional problems stemming from data and assumption inconsistencies, the Companies will need to leverage common data sets and models as tools to inform decision-making throughout the organization. These tools will need to be coupled with enterprise applications and planned to meet emerging and future needs over time. The GMS initially proposed investments over a 5-year period of 2019 through 2023; however, there have been changes and delays in implementation that affected the envisioned timelines. The ADMS will take four and a half years to complete the three-release implementation and the Field Device deployment is anticipated to take five years after Commission approval of this application. This Field Device deployment is intended to ramp up deployment of Field Devices to address current and anticipated grid needs to provide customers with a resilient, reliable, and quality while increasing DER interconnection. The Phase 2 Field Device deployment is not intended to deploy Field Devices system wide, and the deployment will be prioritized based on the areas with the greatest need. Because the deployment is not system wide, there will be continuing need for Field Device deployment after the Phase 2 deployment is complete to address future grid needs, but those deployments will be part of the normal budgeting process for asset management and capital requests. Technology is evolving at a rapid pace, and the adoption of DER and renewable resources in pursuit of the RPS goals creates dynamic conditions on an evolving distribution grid. The IGP process will identify new projects and the priorities for future grid investment and modernization. As a result, the Companies will need to continually assess the needs of the customers and the grid.

XI. PROJECT COSTS

As detailed in Exhibits B (*Updated Project Justification with Business Case Support*) and H (*Updated Bill Impact)*, the Companies estimate the total Capital, Deferred, and O&M costs of the Project through implementation to be $104.3 million. These costs include $56.1 million in implementation and support costs expected to be incurred following Commission approval (assumed in 2020) through the end of 2026 and [redacted] in pre-implementation O&M expenses. In addition to the $56.1 million in implementation costs, beginning in 2022 the Companies estimate that they will incur an average of $3.0 million in ongoing, incremental O&M expenses annually.

The Capital, Deferred, and O&M costs for the Project's implementation include costs for: (1) internal labor; (2) materials; (3) outside services; (4) other; (5) overheads; and (6) AFUDC, as described in Exhibit B (*Updated Project Justification with Business Case Support*). These include costs for products and services to be supplied by third-party vendors. As detailed in

Exhibit E (*Procurement Process*), the Companies obtained vendor responses through their formal RFP process.

XII. ACCOUNTING AND RATEMAKING TREATMENT

The Companies are requesting approval to recover the Capital, Deferred, and O&M costs of the Project implementation (totaling $ 104.3 million), [redacted] million of pre-implementation O&M expense, and an average of $3.0 million of annual, incremental post-implementation O&M expenses. The accounting and ratemaking treatment proposed to be applied to the Project is detailed in Exhibit C (*Accounting and Ratemaking Treatment*) and in Exhibit D (*Exceptional Project Recovery*). The Project is comprised of interrelated components consisting of traditional capital expenditures, deferred software expenses, and expense elements necessary for a smooth, cost-conscious deployment.

A. ACCOUNTING TREATMENT

The proposed accounting for the Project 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 12-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 the ADMS 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."[51] The Companies will incur incremental Expense Costs for training, as well as on-going post go-live costs to operate and maintain the ADMS. To the extent that these costs are not recovered in current rates, the Companies plan to seek recovery of these costs through the EPRM adjustment mechanism.

Additionally, the Companies are seeking to defer O&M costs incurred prior to Commission approval for training and change management pre-implementation costs that are necessary for a successful implementation. The Companies are seeking recovery of these costs through the EPRM adjustment mechanism,.

The proposed accounting for each of the components of the Project is described in Exhibit C (*Accounting and Ratemaking Treatment*).

B. EXCEPTIONAL PROJECT COST RECOVERY

The Companies seek recovery of the Capital Costs, Deferred Costs, and Expense Costs of the Project through the EPRM adjustment mechanism until new rates become effective that provide cost recovery for the Capital Costs, Deferred Costs, and O&M Costs for the Project for each respective company.

The purpose of the EPRM is to provide a mechanism for recovery of revenues for net costs of approved "Eligible Projects" placed in service during a Multi-Year Rate Period that are not provided for by other effective tariffs, the Annual Revenue Adjustment, Performance Incentive Mechanisms, or Shared Savings Mechanisms.[52] As noted in Exhibit D (*Exceptional*

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[51] 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.
[52] EPRM Guidelines, Section II.A1.

Project Recovery), attached hereto, the Companies maintain that the Project 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 EPRM Guidelines. In addition, as further discussed in Exhibit D (*Exceptional Project Recovery*), the Companies submit that this Supplement, including the attached business case,[53] satisfies the criterion set forth in the EPRM Guidelines. A detailed illustrative EPRM calculation for the Project is provided in Exhibit I (*Hawaiian Electric Companies' Decoupling Calculation Workbook*).

C. <u>BILL IMPACT</u>

As shown in Exhibit H (*Updated Bill Impact*), the Companies estimate that the average monthly bill impact of the ADMS component for a typical residential customer would be:

- $0.21 at Hawaiian Electric for a customer using 500 kWh, ranging from $0.11 to $0.28;
- $0.82 at Hawaiʻi Electric Light for a customer using 500 kWh, ranging from $0.45 to $1.05; and
- $0.76 at Maui Electric for a customer using 500 kWh, ranging from $0.41 to $0.99.

The Companies estimate that the average monthly bill impact of the Field Devices component for a typical residential customer would be:

- $0.14 at Hawaiian Electric for a customer using 500 kWh, ranging from $0.04 to $0.32;

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[53] <u>See</u> Exhibit B (*Updated Project Justification with Business Case Support*).

- $0.21 at Hawai'i Electric Light for a customer using 500 kWh, ranging from $0.08 to $0.51; and
- $0.32 at Maui Electric for a customer using 500 kWh, ranging from $0.09 to $0.79.

XIII. GREENHOUSE GAS ANALYSIS

The methodology described below will be utilized to estimate the Greenhouse Gas ("GHG") emissions associated with the Project and the GHG analysis will be filed in this proceeding by May of 2021. Similar to quantitative GHG analyses submitted by the Companies in other applications, it will consider Upstream, Construction, Operations, and Downstream Stages, as shown below.

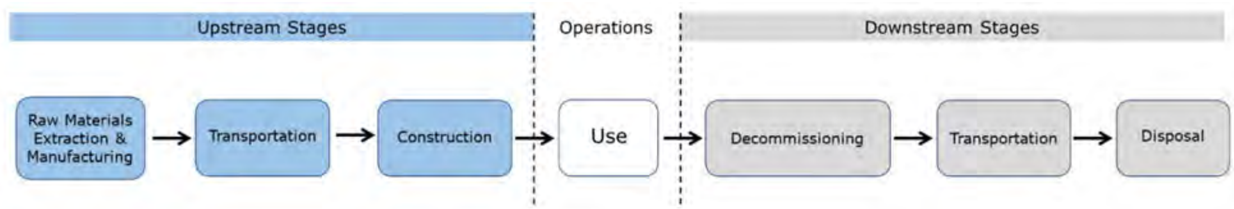

Figure 2

Reasonably foreseeable significant equipment, materials and activities are accounted for throughout the Project lifecycle. The following sections provide an overview of the methodology for analyzing the GHG emissions.

A. <u>UPSTREAM STAGES</u>

Upstream Stages include the GHG emissions associated with raw materials extraction, manufacturing, transportation, and construction stages of the Project, including GHG emissions that occur on-island as well as off-island. GHG emissions associated with raw material extraction and manufacturing are related to equipment and materials installed or used during the

Project. The GHG emissions for upstream stages also take into account the total number of pieces of equipment.

The Transportation and Construction Stages' GHG emissions are calculated using an "inventory approach" in which estimated direct GHG emissions from transportation and construction are calculated based on Project- and location-specific data. The emissions include Upstream transportation for material and equipment from manufacturer locations to the installation locations. The Construction Stage includes GHG emissions produced during installation of the new equipment.

B. OPERATIONS STAGE

Operational Emissions include direct GHG emissions associated with the operation and maintenance of the Project (e.g., the "Operations Stage" shown in Figure 1).

C. DOWNSTREAM STAGES

The Downstream Stages include GHG emissions from transportation, distribution, decommissioning and disposal of the proposed equipment at such time the equipment is decommissioned. The emissions include Downstream transportation for material and equipment to disposal locations.

The estimated GHG emissions will be presented in metric tons of carbon dioxide equivalent (MT CO2e) for the Project. Detailed calculations including assumptions and inputs will be properly documented.

XIV. CONCLUSION

Wherefore, the Hawaiian Electric Companies respectfully request a D&O approving the Requested Approvals as detailed in Section II, above.

DATED: Honolulu, Hawaiʻi, March 31, 2021.

HAWAIIAN ELECTRIC COMPANY, INC.
HAWAIʻI ELECTRIC LIGHT COMPANY, INC.
MAUI ELECTRIC COMPANY, LIMITED

By /s/ Joseph P. Viola

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

Vice President
Hawaiʻi 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 Supplement, and knows the contents thereof; and that the same are true of his own knowledge except as to matters stated on information or belief, and that as to those matters he believes them to be true.

/s/ Joseph P. Viola

Joseph P. Viola

GRID MODERNIZATION STRATEGY WORKING PLAN

On August 29, 2017, the Hawaiian Electric Companies[1] filed their final Grid Modernization Strategy ("GMS")[2] with the Hawai'i 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 to update the existing electric grid infrastructure, which will pave the way for the Companies to achieve Hawai'i's 100% Renewable Portfolio Standard ("RPS") goal by 2045.[3] Following Commission approval of the GMS,[4] the Companies have moved forward to implement the Strategy, starting with the approved GMS Phase 1 ("Phase 1")[5] and the Integrated Grid Planning ("IGP") activities.[6] In adherence with D&O 35268, this 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 have divided the implementation of the GMS into multiple phases. Each phase will evolve the electric grid into a modernized one using a logical progression of features and functionality, with latter phases building upon the capability and functionality of earlier phases. The maturity of the different components of grid modernization,[7] as well as the prioritized need for the functionality and capabilities of each component, drive the order and sequence of each phase of the implementation. This distribution Field Device supplement to and update of the GMS Phase 2 Advanced Distribution Management System ("ADMS") Application ("Supplement") will build upon the Phase 1 advanced metering, telecommunications network, and meter data management system to collect, aggregate, and process meter data. The Phase 2 Field Devices transform distribution automation capabilities with monitoring, sensing, and distribution-level control and automation for advanced operational capabilities managed by grid operators through the ADMS. The intent is to enable functionality and capabilities that will meet both customer and grid needs and to create customer value by further enabling customer energy options and progress toward RPS goals while remaining flexible to adopting emerging

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[1] 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 as the "Hawaiian Electric Companies" or the "Companies."

[2] See Docket No. 2017-0226, *Modernizing Hawai'i's Grid For Our Customers*, filed August 29, 2017.

[3] See Hawai'i 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. 35268, issued on February 7, 2018 ("D&O 35268").

[5] See Docket No. 2018-0141, Decision and Order No. 36230, issued on March 25, 2019.

[6] See Docket No. 2018-0165, Decision and Order No. 36218 and *Integrated Grid Planning Report* and *Integrated Grid Planning Workplan*, issued on December 14, 2018.

[7] See the U.S. Department of Energy's Next Generation Distribution System Platform ("DSPx"), Volume II, *Advanced Technology Maturity Assessment*, available at http://doe-dspx.org/sample-page/dspx-volumes/.

technologies.[8] Grid Modernization is intended to quickly build grid capabilities to enable customer energy options and achieve RPS goals as articulated in the GMS because "the grid we have is not the grid we need."[9]

Beyond Phase 2, some components still require additional evaluation to determine the necessary scope to fulfill customer needs and stakeholder expectations. The Companies will need to evaluate whether their continued efforts can proceed under the Companies' normal budgeting processes or whether any additional grid modernization application(s) to the Commission will be required.

I. GMS IMPLEMENTATION SCHEDULE

The COVID-19 pandemic and other factors have resulted in a slower-than-expected implementation of Grid Modernization. As a result, the initially envisioned 2023 end date for the deployment of Grid Modernization investments is expected to continue through 2026, providing the time needed to implement the ADMS and deploy the Field Devices.[10]

The multiple phases for the GMS implementation, which were depicted in the Phase 1 Application, are updated in Figure 1, and the scope of work for the different phases has remained consistent. This Phase 2 Project will enable customer energy options by empowering grid operators with the requisite ADMS software and distribution Field Devices to effectively manage a grid reliant on renewable and distributed energy resources. The planned ADMS release schedule will effectively build capabilities over time to enable monitoring of the distribution system as well as enable the control and automation functionality required to safely and reliably support a distributed and renewable resource future.

[8] The term "customer energy options" as utilized in the Grid Modernization Applications 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").

[9] See Docket No. 2017-0226, *Modernizing Hawai'i's Grid For Our Customers*, filed August 29, 2017, p. 3.

[10] This timing is dependent upon Commission approval of the ADMS and Field Device applications by the end of 2021. The grid modernization Field Device schedule is a five-year deployment to jump-start deployment of 45% of the estimated total number of devices.

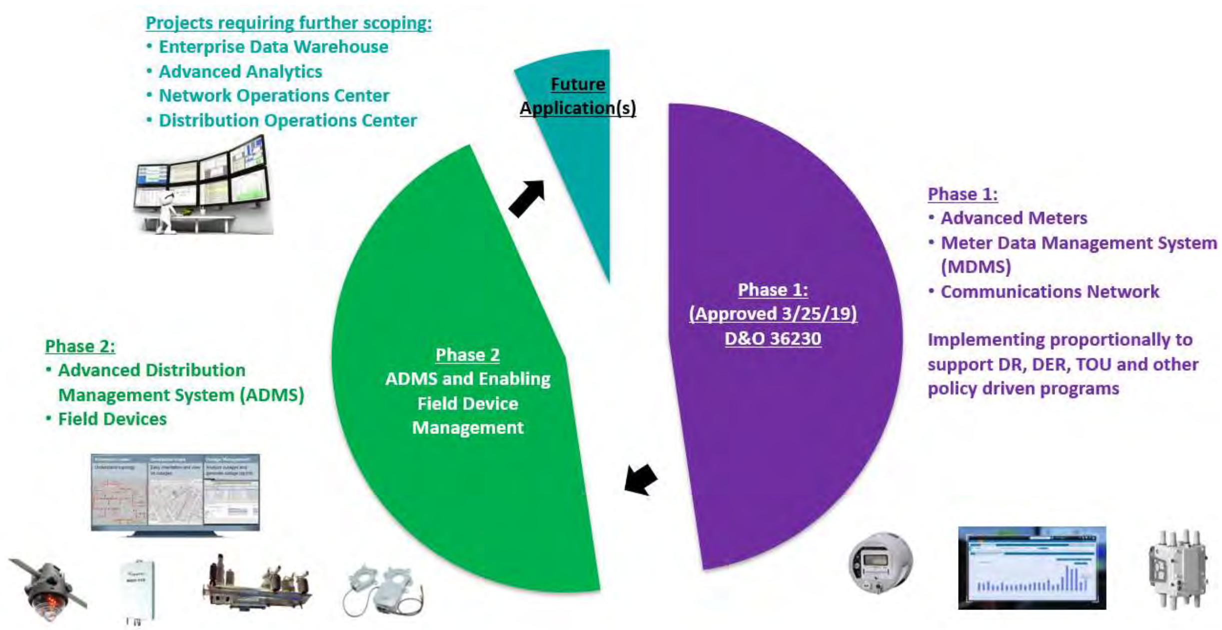

Figure 1

The scope for future phases of 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. Analytics needed beyond what is provided by the MDMS and the ADMS may lead to requests for additional capabilities for subsequent GMS implementation phases in the future. However, this additional investment should be driven by customer feedback as the number of customers adopting DER and receiving advanced meters grows.[11] The Companies anticipate that any applications associated with future projects beyond this Supplement will be submitted based on the scope and timing for investments in these grid modernization components and in coordination with any broader enterprise systems planning processes the Companies may undertake in the future.

Recognizing the converging topics and impacts across our systems, the Integrated Grid Planning ("IGP") approach was initially conceived in the development of the GMS.[12] For future requirements and long-term plans for distribution, IGP will help to guide the strategies pursued by the Companies. However, the key objectives targeted by the GMS remain urgent today. The distribution system needs to be modernized to enable a robust, reliable, and resilient distribution system capable of interconnecting and utilizing DER to provide grid services while meeting RPS goals. The distribution system has become the largest point of generation interconnections, and this Project kick-starts the needed improvements to distribution monitoring, control, and

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[11] It would not be prudent to spend too much time, money, and effort on fully integrating the customer energy portal with the billing system while a broader customer-facing solution is being contemplated and the number of customers with advanced meters is initially a small but expanding subset of total service customers.
[12] See Integrated Grid Planning ("IGP") Docket 2018-0165.

automation to reach near-term goals. The GMS implementation is designed to meet DER, grid services, and advanced rate expectations and timelines that customers, stakeholders, and the Commission have laid out in related dockets and through engagement. Future grid projects, including those identified in IGP, will build on this foundation.

A. ACCELERATING ADVANCED METERING DEPLOYMENT

In the time since Phase 1 was approved for implementation, the Companies have continued to provide semi-annual status reports consistent with D&O 36230. On September 30, 2020, the Companies provided a letter to the Commission outlining the plan to transition to a proportional opt-out approach for advanced meter deployment. The goal of this shift in strategy is to deploy more advanced meters faster and in a more cost-effective manner, considering the Phase 1 cost recovery caps for advanced metering and telecommunications.[13] The Commission approved the opt-out strategy on March 3, 2021.[14] In order to deploy more meters faster, the Commission, through D&O 37507, ordered a performance incentive mechanism (PIM) related to advanced meter deployments.[15] The proportional "as needed where needed" approach for Grid Modernization deployment and motivation to meet or exceed PIM targets will help the Companies to rapidly deploy advanced metering and will assist in reaping the benefits of the insights afforded by the advanced meters.

II. PHASE 2 GRID MODERNIZATION

The goal of Phase 2 for the Companies' GMS implementation is to enable advanced distribution monitoring, control, and automation capabilities. To achieve this functionality, the application includes an ADMS, which serves as a back office system for distribution operators to efficiently monitor, visualize, and control distribution grid conditions utilizing substation automation[16] and distribution automation Field Devices in a coordinated fashion, improving grid performance beyond what can be accomplished through individually operating or autonomously functioning Field Devices.[17] The ADMS includes systems integration to connect distribution monitoring with existing Energy Management Systems, the recently approved Decentralized Energy Management System ("DEMS")[18], the Geographic Information System ("GIS"), which

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[13] See Docket No. 2018-0141 D&O 36230, filed on March 25, 2019.
[14] See Docket No. 2018-0141 Order 37655.
[15] See Docket No. 2018-0088, filed on December 23, 2020.
[16] Investment in substation automation Supervisory Control and Data Acquisition ("SCADA") and other substation automation equipment is outside the scope of Grid Modernization. However, the ADMS will still interface with the substation automation equipment.
[17] Reclosers and fault indicators have been utilized for many years, functioning autonomously and providing benefits. However, the communications and ADMS interfaces to provide system operators with distribution system situational awareness and control through these Field Devices has evolved significantly as a core component of Grid Modernization.
[18] See Docket Nos. 2015-0411 and 2015-0412. The DEMS is the name of the product that was approved in the DRMS docket. As the Commission recognized with D&O 36476, the line between DR and DER is nuanced from a policy and program perspective. Similarly, the differences between the functions associated with the management software capabilities are nuanced. For the purposes of the Companies' selected architecture, we will be discussing things in terms of DEMS and ADMS. The industry terms of DRMS and DERMS do not comport

tracks the geographic location of components of the distribution grid, and the Phase 1 components.

The ADMS is an operational software system that enables grid operator situational awareness and control by using a combination of data from the distribution automation Field Devices described in this Supplement, the Phase 1 advanced meters, and substation automation devices, including SCADA. The ADMS builds upon the Phase 1 components, particularly maximizing the capabilities of the advanced meters and the field area network ("FAN"). Beyond enabling more complex time of use ("TOU") and DER tariffs and programs and providing customer insights through the customer energy portal, the Phase 1 advanced meters perform two primary functions to support distribution system management: (1) sending outage and voltage notifications to the ADMS, which then notifies distribution operators when customers are experiencing those conditions, which enables corrective action to mitigate those issues, and (2) supplying data in 5-minute intervals to provide planning and engineering insights into the complex supply and demand dynamic given the growing customer adoption of and system reliance on DER.[19]

As articulated in the Application and expanded further below, the ADMS is able to coordinate operational decisions by taking into account area/regional information alongside circuit information. This situational awareness is effectively data contextualization afforded by systems integration and a variety of measurement locations. This project not only allows for system operators to control Field Devices remotely but also to make decisions with more informed context and insights. Rather than rely only on settings and functionality controlled locally by each individual device, the ADMS is able to coordinate schemes to better serve customers. While individual circuit reclosers provide the benefit of reducing the number of prolonged outages, multiple reclosers, with enabling telecommunication for monitoring and control coordinated by an ADMS FLISR scheme, will provide additional customer benefit by notifying system operators of the outage and minimizing the number of customers affected.

Coordinating the behavior of the distribution system will grow in importance as DERs and grid-scale inverter-based generation become a larger portion of the generation portfolio in pursuit of the state's 100% RPS. At their core, smart switches are system and circuit protection devices designed to protect and isolate portions of a circuit from fault conditions that could lead to dangerous situations. By safely de-energizing the circuit, the protection device protects customer and grid equipment from overload and fault currents. However, circuit protection is complicated by the need for customer-sited generation. Circuit-level events could impact the broader performance of the island system without appropriate measures. Further complicating this, inverter-based generation (such as that produced by photovoltaic solar cells) does not provide the same power characteristics as traditional generation, so priority should be given to

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neatly with the Companies' unique and industry-leading vision, wherein customer-cited resources will be relied upon for routine grid operation.

[19] Note that PLC/PLX metering will provide 15-minute rather than 5-minute interval data. See Docket No. 2018-0141, Responses to Consumer Advocate Information Requests IR-5, dated October 24, 2018.

adaptive protection schemes that work in low inertia and low-fault current conditions (those conditions where generation comes from multiple sources).

Circuit and system protection in high DER environments is an area of research in the industry, and the Companies will continue to adopt best practices to better serve our customers. The broader point is that centralized coordination of Field Devices enabled by the ADMS is needed today and will help the Companies transition to 100% RPS in the long term.

A. ADVANCED DISTRIBUTION MANAGEMENT SYSTEM

In the time since the ADMS Application was filed on September 30, 2019, the Companies have continued to refine the ADMS planning activities in an effort to expedite the implementation timeline following a favorable ruling on the Application. These planning activities include (1) conversations with the vendor on the scope of work, (2) reworking the release schedule to align with the timelines articulated in the IGP and consistent with the likely timing of a Commission D&O on this matter, and (3) refining the system architecture to ensure ADMS functionality is not lost during power and telecommunications outages. With respect to the updated release schedule,[20] the Companies have effectively shifted Fault Location Analysis to Release 1 because of the urgent need for those capabilities and to coordinate with the Field Device supplemental application.

Of the three operating electric companies associated with the GMS, Hawaiian Electric is the only one that currently has an Outage Management System (OMS). The OMS module of the ADMS will therefore significantly improve the outage management capability of both Maui Electric and Hawai‘i Electric Light and incrementally improve Hawaiian Electric’s capability. The OMS will replace what is now a manual process to coordinate outage response at Maui Electric and Hawai‘i Electric Light that utilizes paper maps of the islands. Additionally, all three operating companies rely on customer phone calls to customer service representatives (“CSRs”) to identify outages and estimate the extent of an outage. The OMS will automate certain aspects of that process, including utilization of outage alerts from advanced meters to identify the affected customers and integration with the SAP work management system to provide instructions to restoration field crews. In the interim, Maui Electric and Hawai‘i Electric Light are working to roll out outage displays and improve customer outage maps that provide customers with outage information and estimates. The OMS capabilities and outage response will be further enhanced by the fault location isolation and service restoration (“FLISR”) capabilities of the ADMS and the outage notifications from the Field Devices and automation provided by the smart switches (reclosers and smart fuses).

B. FIELD DEVICES

Although the full implementation of Field Devices for the grid modernization effort will follow the approval of this Supplement, the Companies have already deployed limited amounts of Field Devices through both field pilots and current budgeting processes to begin to address current needs for grid reliability, sensing, and voltage control at specific locations, such as at

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[20] See Exhibit B Section III

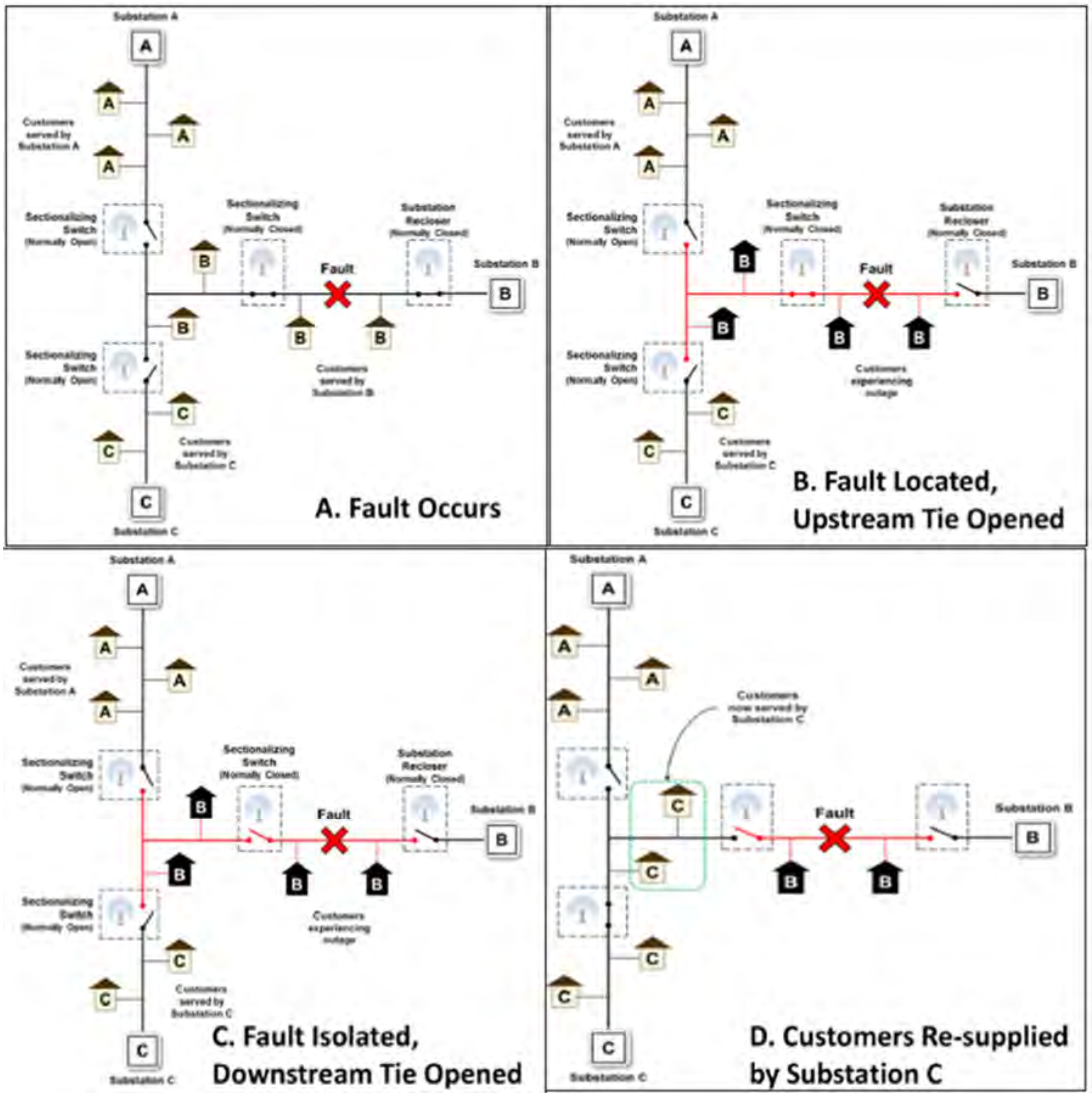
circuits or portions of circuits where reliability performance has been poor. Another example of Field Devices is the deployment of secondary VAR controllers on circuits that achieved or exceeded circuit DER hosting capacity. However, the larger-scale Field Device deployment, which will allow for a more proactive deployment of Field Devices to provide enhanced circuit capability (hosting capacity, reliability, etc.) commensurate with the needs of circuits or regions, is contingent upon approval of this Supplement. More specifically, the intent of this Supplement is to synthesize efforts at a program level to address both customer and grid needs and that the deployment of Field Devices is optimized across the Companies.

The Companies have taken a two-step approach to planning Field Device deployments to date. Step one involves identification of a need (e.g., control voltages of secondary nodes, improve reliability, enhance resiliency, mitigate wildfire risk, and enhance circuit/system protection) and creation of a high-level plan that considers the unique characteristics of each island grid. From there, certain circuits and feeders are prioritized for Field Device deployment based on specific circuit hosting capacity, and power quality (voltage), reliability, and resiliency considerations. Distribution planning and protection engineers then assess the circuit topology, historical performance, and forecasts to develop a plan for each of those prioritized circuits. These circuit-specific tactical plans may refine the high-level strategic plans into detailed engineering documents that consider the characteristics and specifications of each circuit in order to optimize device deployments such that they are capable of meeting the various system needs. The device quantities specified in this Supplement are estimates built from the high-level plans, which incorporate lessons learned from initial device deployments.

These tactical deployment plans will consider a variety of factors for Field Device placement aimed at enabling both centralized and decentralized situational awareness. With respect to centralized situational awareness, the system operator and ADMS will be provided with more granular measurements of system conditions at a greater number of locations on the system to proactively adjust settings and reconfigure the system. Given the dynamic voltage and load conditions that result from customer DER and electrification, the tools to manage power flow are growing in importance along with the expectation of their performance. The substation and distribution equipment used historically – SCADA, load tap changers, phase-rebalancing, mid-line capacitor bank controllers, voltage regulators, and static transformers – provide voltage control that was adequate for providing customers with power from centralized generation. However, this equipment cannot provide the appropriate granularity or controls to support two-way power flow with high levels of customer-sited DER. With advanced switches, the system can adjust feeder configurations to mitigate voltage violations, but only if the sensing is available on the distribution system to inform those operational decisions. Where reconfiguration and traditional methods do not meet needs and voltage violations persist beyond the autonomous capabilities of smart inverters utilizing IEEE 1547-2018 functionality, secondary VAR controllers will be deployed to ensure that customer voltages remain within standards.[21]

[21] As part of the tactical deployment plans for secondary VAR controllers, the engineer will validate that the application of a VAR controller is the suitable mitigation approach. This typically will involve assessing the patterns of the voltage problems (reoccurring at similar points in the daily load curve e.g. linked to DER activity) and if there

As shown in Figure 2**Error! Reference source not found.**, also found in the Grid Modernization Strategy as Figure 21, switches can provide new routes for customer power flow – both to receive from the bulk system and to allow their rooftop PV generators to provide the necessary energy for the rest of the island. This reconfiguration capability provides outage management, but it also helps to manage power flow conditions observed through sensing and advanced meters.



are associated power quality issues such as flicker and phase imbalance. Secondary VAR controllers may not necessarily be the only solution; other solutions may be considered to resolve voltage issues that include, but are not limited to, upgrading conductors, balancing generation and load per phase, non-wires alternatives, etc. Hawaiian Electric will evaluate the solution of best fit on a case-by-case basis.

Figure 2

The ADMS software will provide grid operators with situational awareness and recommend switching schemes to minimize the number of customers affected by an outage. Grid operators can then utilize the ADMS to implement the switching scheme with remote intelligent switches.

Certain use cases will need to maintain automated responses to manage grid conditions in real time. Primarily, protection schemes will need a decentralized situational awareness as DER and bulk-scale renewables continue to shift the dynamics of the grid. The equipment (fuses and electromechanical relays) that has traditionally been used to detect outage (fault) conditions and safely de-energize the system is strained trying to detect, isolate, and limit the impact of potentially dangerous conditions in a decentralized power flow. Effectively, normal operating conditions could look like overcurrent events, causing protective equipment to unnecessarily de-energize the system. In addition to the traditional reliability benefits, electronic smart fuses provide settings that can be used to recognize low-fault duty conditions and maintain customer and protection device functionality as more DER are incorporated into the system. The practice of adjusting protection device settings according to system conditions is known as adaptive protection and is managed through the ADMS.

The distribution automation Field Devices are either necessary or enhance those use cases to utilize the ADMS functionality and achieve the ADMS benefits described. Table 1, below, identifies the ADMS use cases where Field Devices are either required, enhance the functionality, or support the end goal. In many instances, the sensing capabilities of the Field Device result in support for a use case even if the primary use of the Field Device is not related to the use case. The Field Device enhances the ADMS use case if the additional sensing, control or automation capabilities improve use case execution relative to the use case being performed without the Field Device. For example, the top three use cases are related to SCADA and substation automation. Because the Field Devices are distribution automation rather than substation automation devices, they are not required for these SCADA use cases; however, the sensing capabilities of the Field Devices provide more data and precision through situational awareness of the distribution system, which either enhances or supports the use cases.

R = Required E = Enhance S= Support	Line Sensors	Remote Fault Indicator	Remote Intelligent Switch	Secondary VAR Controller	Advanced Meter
Use Case 1 – SCADA Events and Alarming	E	E	E	E	
Use Case 2 – SCADA Control			S	S	
Use Case 3 – SCADA Control System Updates	S	S	S	S	
Use Case 4 – Outage Management	E	E	E	S	S
Use Case 5 – Detect Restoration Issues	E	E	E	E	S
Use Case 6 – Switching Management	E	E	E		
Use Case 7 – Fault Location Analysis	R	R	R	E	E
Use Case 8 – Fault Location Isolation & Service Restoration ("FLISR")	E	E	R	S	S
Use Case 9 – State Estimation	E		E	E	S
Use Case 10 – Powerflow Studies	E		E	E	
Use Case 11 – Volt/VAR Optimization	R		S	R	E
Use Case 12 – Load Management	E				R
Use Case 13 – Forecasting	E		S	S	E
Use Case 14 – Dynamic Relay/Protection Settings	E		E	E	
Use Case 15 – EMS Coordination	S		S	S	S
Use Case 16 – GIS Updates	S	S	S	S	S
Use Case 19 – Asset Management Coordination	S	S	S	S	S

Table 1

The Companies have historically utilized a fuse-blowing philosophy to isolate outage conditions. This practice ensures that outages are limited to only the section of the circuit where the outage condition exists. However, since most outages are temporary in nature and a fuse-blowing scheme requires a crew to replace the fuse to restore power, the Companies are shifting to a fuse-saving scheme in instances where the application is most useful. In these schemes, reclosers and smart fuses are set to operate faster than the fuse, saving the fuse but allowing the temporary fault condition to clear. Upon reclose, if the outage condition persists downstream of the fuse, the fuse melts, de-energizing that portion of the grid and sending an outage alert to the OMS, and a field crew is deployed to address the situation. Since the reclose "saved" the fuse the first time, fuse-saving schemes have reliability benefits associated with reducing the time to clear temporary faults, but they may subject customers to additional momentary interruptions as the system attempts to clear the fault condition. Since there are 7078 fuses on Oahu's distribution grid with various ratings, it is unreasonable to retrofit all of these with a fuse-saving philosophy in the next few years. Instead, the Companies are tactically placing smart fuses to operate as fuse-saving devices to minimize the number of blown fuses for temporary faults.

III. FUTURE PHASES FOR GMS IMPLEMENTATION

Some GMS components require further 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 examining the increasing volume of data that will be collected through the deployment of Field Devices and advanced metering. Analytics capabilities, which both assist in more efficient grid operations and provide insight for future planning and forecasting, are continuing to evolve. 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. There is also an immediate need for data historians to archive the MDMS data and a future need to archive the ADMS data in near-real time, and these data historian databases can be queried for analytical purposes. As a result, funding for a data historian is included in this Phase 2 application and described further in Exhibit B Section III.C.2. After the MDMS and ADMS are functioning, a gap analysis will be performed to determine what, if any, additional analytics capabilities are required to progress 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, although for now 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 during and following the implementation of GMS Phase 2.

Exhibit B

Grid Modernization Strategy Phase 2 ADMS and Field Device Application

Updated Project Justification with Business Case Support

PROJECT JUSTIFICATION WITH BUSINESS CASE SUPPORT

I. INTRODUCTION

This project will implement a new Advanced Distribution Management System ("ADMS") in the Hawaiian Electric Companies' grid control rooms[1] and deploy Field Devices to provide greater visibility, control, and optimization of the distribution system for more reliable operations of the two-way flow of electricity as the number and amount of distributed energy resources ("DER") continues to rise. Additionally, the solution will improve resilience by allowing Grid Operators to quickly adapt to changing grid conditions and rapidly recover following power outages and disruptions by enhancing situational awareness and assisting in restoration triage. The existing outage management processes will also be modernized to leverage ADMS reporting and automation features that improve customer communications, incident response, and operational efficiency.

II. BUSINESS CONTEXT

A. POWER SUPPLY IMPROVEMENT PLAN

The Hawaiian Electric Companies' December 2016 Power Supply Improvement Plan ("PSIP") update outlined the specific actions necessary to accelerate the achievement of Hawai'i's 100% Renewable Portfolio Standard ("RPS") by 2045:

- Exceed Hawai'i's 2020 RPS and achieve a consolidated RPS of 52% by 2021;
- Maximize DER – compensated;
- Make high use of demand response ("DR") programs;
- Aggressively seek grid-scale renewable resources, leveraging federal tax credits;
- Pursue grid modernization to enable continued integration of renewable energy;
- Preserve long-term flexibility to use emerging technologies and accommodate changing circumstances; and
- Reduce operations that use fossil fuels and contribute to greenhouse gases.

The prescribed actions take advantage of available resources, respond to customer preferences, and reduce dependence on oil and its price uncertainty as quickly as possible while preserving flexibility over the longer term to address changing circumstances to take advantage of new opportunities that may arise and to explore emerging technologies. The Integrated Grid Planning ("IGP") project is working with stakeholders through multiple planning cycles to

[1] The "Hawaiian Electric Companies" or the "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").

progress towards a 100% RPS future with a combination of customer DER and utility scale renewable and energy storage resources.[2]

B. GRID MODERNIZATION STRATEGY

Grid modernization is a foundational activity, required to realize Hawai'i's clean energy objectives while operating a safe and reliable electric grid. Integrating an increasing amount of customer-supplied renewable energy creates a critical need for modernizing the distribution grid and control room technology to support two-way power flows without sacrificing reliability or safety. This is necessary in order to accommodate expected growth of distributed generation photovoltaics ("DG" and "PV", respectively) on the Hawaiian Electric, Maui Electric, and Hawai`i Electric Light grids, respectively.

A modernized grid empowers customer choice and demand-side flexibility, where DER – including solar PV, battery energy storage systems ("BESS"), electric vehicles ("EV"), and DR resources – can be operated at every home. It supports the Electrification of Transportation ("EoT") by enhancing the ability for the distribution grid to manage the variable demand of EVs, charging stations, roaming vehicle fleets, and mass transit systems. A modernized grid also supports smart cities and microgrids with improved ability to manage intermittent electrical islanding of distribution grid subnetworks.

The Companies' Grid Modernization Strategy[3] provides near- and long-term plans for the Companies to deploy advanced technologies and back office systems to update the electric distribution grid. Phase 1 of the GMS consisted of advanced meters, a Meter Data Management System ("MDMS"), and Field Area Network ("FAN") telecommunications. The Companies are now requesting funding to implement Phase 2 of the Strategy, which includes the implementation of an ADMS and deployment of distribution automation Field Devices, which are critical to the continued addition of DERs, reducing outage restoration time, improving outage communication to the customer, improving visibility and control of DERs, and optimizing resources during both normal operating conditions and in contingency situations. See Section IV for a more detailed benefits discussion.

C. PHASE 2 IN CONTEXT

Within the context of the PSIP, GMS, and ongoing IGP and PBR activities, the Companies maintain that executing the near-term plan articulated in the GMS is integral to achieving the vision of a modern grid. The ADMS is needed to coordinate a distributed system where two-way power flows are common. The Field Devices are needed to provide situational awareness and enhance reliability. Both work in concert to increase customer energy options and provide the improved quality of service that our customers expect.

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[2] See Docket No. 2018-0625

[3] See "Modernizing Hawaii's Grid For Our Customers," filed in Docket No. 2017-0226 on August 29,2017 ("GMS," "Grid Modernization Strategy," or "Strategy").

1. ADMS Components

Vendor-supplied ADMS solutions are typically comprised of four foundational features: (1) an Outage Management System ("OMS") used to manage and track outages; (2) a Distribution Management System ("DMS") that monitors and controls switching at the distribution level, including distribution SCADA, in conjunction with Distribution Automation ("DA"); (3) "Advanced Applications" — analytic functions for forecasting, simulating, studying, and optimizing the impacts of different network switching configurations and loading conditions; and (4) a Distributed Energy Management System ("DERMS"). The Companies have already implemented the DERMS through the Demand Response Management System ("DRMS") project and Decentralized Energy Management System ("DEMS") implementation.[4]

The goal of this Application is to enable the implementation of the remaining three ADMS modules. Representative components of these three ADMS modules include:

Components	Description
OMS Components	**Outage Management System Modules/Functionality**
Trouble Call Management	A module for accepting and recording trouble calls from customers. This includes outage and other trouble conditions.
Crew Management	Also known as Mobile Client, Mobile Device Functionality for Field Technical Services, or First Responder Crews
Trouble Order Management	An outage management function that performs automatic grouping of trouble calls into trouble orders that represent the calls that are likely due to a common cause. Trouble orders can be sorted by multiple factors for restoration prioritization. Trouble Order Management includes a geographical map display for the System Operator. The OMS then coordinates associated trouble orders through SAP Work Orders to provide specific instruction and coordination to restoration field crews.
Estimated Time to Restoration	An estimate of the time until an outage is restored based upon known conditions, including time of day, number of crews on duty, outage prioritization rules, and size of outages. ERTs are calculated by an ADMS and are provided as a customer service. Outage management functions of an ADMS help maintain individual and global estimates of restoration times. Also sometimes called Estimated Restoration Time (ERT).

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[4] See Docket Nos. 2015-0411 and 2015-0412. The DEMS is the name of the product that was approved in the DRMS docket. As the Commission recognized with D&O 36476, the line between DR and DER is nuanced from a policy and program perspective. Similarly, the differentiation between the functions associated with the management software capabilities is nuanced. For the purposes of the Companies' selected architecture, we will be discussing things in terms of DEMS and ADMS. The industry terms of DRMS and DERMS do not comport neatly with the Companies' unique and industry-leading vision wherein customer-cited resources will be relied upon for routine grid operation.

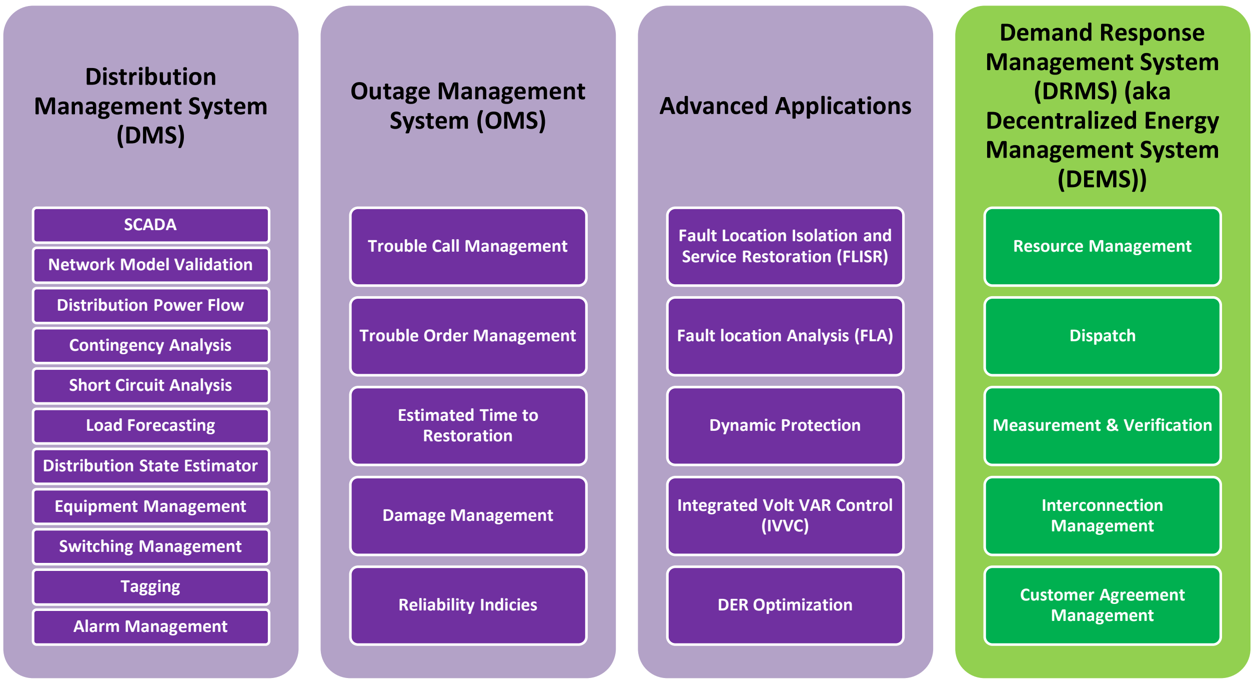
Damage Management	A module that assists field personnel who collect information on the location and types of damage observed in the field. The collected information is used in the ADMS to assist in making better assignments of crews, determining the equipment that is required for repair and also make better estimates of restoration times. Sometimes also called Damage Assessment.
Reliability Indices	A module for generating reports from ADMS outage management functions that provide metrics that quantify reliability, including system outage duration (SAIDI), outage frequency (SAIFI) and other industry standard reliability metrics.
Training Simulator	A module that simulates the behavior of the distribution system and other external inputs to an ADMS that mimics real responses to user's actions to assist in the training of Grid Operators. Simulated scenarios can include faults, planned outages, and storms. Also called Distribution Operator's Training Simulator (DOTS).
DMS Components	**Distribution Management System Modules/Functionality**
SCADA (D-SCADA)	Distribution Supervisory Control and Data Acquisition - A system of remote control and telemetry used to monitor and control the distribution system and associated feeder automation.
Network Model Validation	A module that manages and validates the electrical model imported from a Geospatial Information System (GIS).
Distribution Power Flow (DPF)	An analysis application that calculates power system operating conditions, including voltage and line flows, given a system model and either real-time measurements or forecast generation and load. For Distribution, the DPF algorithm must also be unbalanced to take into account that the system loads, generation, and model cannot be assumed to be identical on all three phases. Also sometimes called a Dispatcher's Power Flow.
Contingency Analysis	Contingency analysis is a module that evaluates the effects of and calculates any overloads or voltage violations resulting from potential contingency events.
Short-Circuit Analysis	A module that determines the magnitude of short-circuit current at a particular location and type of fault. Short-circuit analysis is used for fault location analysis.
Load Forecasting	A module for calculating the load (and distributed generation) on the distribution system at a given date/time.
Distribution State Estimation	Distribution State Estimation (DSE) - A module that provides estimation of the entire voltage and power flow state of distribution system using real-time measurements

	from SCADA and pseudo-measurements such as estimated load and distribution generation.
Equipment Management	The tracking and monitoring of distribution system equipment by the ADMS.
Switching Management	A module that assists in the preparation and management of planned and emergency switching sequences. Sometimes also called Switching Order Management (SOM).
Tagging	A function that supports the tracking of tags that are placed on field equipment for the purposes of safety and protection of the field crews while performing work.
Alarm Management	The function of an ADMS that alarms and alerts the distribution operator of abnormal conditions that require attention and/or action to be taken.
Advanced Applications Components	**Advanced Application Components**
FLISR	Fault Location, Isolation, and Service Restoration - A module that automatically determines the location of a fault and rapidly reconfigures the flow of electricity so that some or all customers can avoid experiencing outages.
FLA	Fault Location Analysis - A module that identifies the distance a fault occurs from the source and aids in locating faults.
Dynamic Protection	Advanced Protection Schemes and Device Coordination
IVVC	Integrated Volt-VAR Control - A software module that accesses the advanced meter data for both operational/situational awareness and system studies. Also sometimes called Volt-VAR Optimization.
DER Optimization	The optimization of the distribution system to support the use of Distributed Energy Resources (DER).

The Companies' proposed ADMS investment is foundational in nature and required to give Grid Operators the tools to monitor, control, and automate the evolving distribution grid to support increasing amounts of customer-owned renewable and distributed resources. Figure 1 illustrates the multiple modules that comprise an ADMS, including the existing DEMS. The catalyst for this ADMS investment is to enable safe and reliable grid operations while increasing both centralized and distributed clean and renewable (but also variable) energy resources in pursuit of Hawaiʻi's RPS. Other utilities, such as Sacramento Municipal Utility District

("SMUD"), Southern California Edison ("SCE"), and Pacific Gas and Electric ("PG&E"), are recognizing the need for the ADMS as a foundational investment.[5,6]

Industry Reference Components of an Advanced Distribution Management System



*The DEMS was implemented per D&O 36476

Figure 1 Industry Components of an ADMS

[5] See Electric Energy Online, "SMUD Selects OSI Technology for a New Advanced Distribution Management System." May 10, 2019: https://electricenergyonline.com/article/energy/category/automation-it/53/699695/open-systems-international-inc-osi-smud-selects-osi-technology-for-a-new-advanced-distribution-management-system.html

[6] See Utility Dive, "PG&E may answer the billion dollar grid modernization question." August 26, 2019: https://www.utilitydive.com/news/pge-may-answer-the-billion-dollar-grid-modernization-question/561146/

2. ADMS Integration

The proposed ADMS project will replace and expand on the functionality of the current Hawaiian Electric Outage Management System ("OMS") (available for the Hawaiian Electric system only) with a new solution deployed for all three operating Companies. Hawaiian Electric's original OMS was installed in 2006–2007 and has been regularly updated since. However, that system is now over 12 years old and the Companies are seeking to install an OMS that is integrated with a DMS. In today's market, an OMS is now a subset of functionality within an ADMS and the Companies are looking to procure and install a single integrated solution to reduce integration and operation costs and risks with a single vendor solution. Selecting a vendor that has integrated an OMS into its ADMS product introduces less risk than is likely when integrating one vendor's ADMS to another vendor's existing OMS.

The ADMS functionality outlined in the previous section and depicted in Figure 1 will depend heavily on the data coming from many different sources. Both software systems, such as the GIS geo-locational data, and field equipment provide data for the ADMS to perform its functions. More information on system integration can be found in Exhibit F (*GMS System Architecture and Cyber Security*). As was outlined in the Exhibit G (*Telecommunications Network Considerations*) in the Phase 1 Application, the FAN will ultimately facilitate data transport between Field Devices and the ADMS, in addition to its other functions. The ADMS will be capable of receiving data from distributed equipment through additional routes, including:

- Through the Companies' Wide Area Network ("WAN"), which provides SCADA telecommunication into the control centers. The addition of the ADMS will help to maximize the investment in SCADA infrastructure.
- Through leased lines or cellular LTE communications. This option may be used to retrieve data from DA devices that are in between the substation and customers.
- Through the FAN
- Through customer and DER aggregator telecommunication pathways (e.g. Internet) utilizing a variety of communication protocols. This option utilizes the DEMS and Aggregator data integration to facilitate data transport to the ADMS and/or DEMS.
- Additionally, the current outage reporting process utilizing customer calls or the smart phone application to report an outage will transition to provide a pathway of communication for outage reporting to the OMS module of the ADMS.

The ADMS processes all of the distribution monitoring data delivered through these various telecommunication pathways with advanced algorithms to provide situational awareness and tools for the operator, including distribution state estimation, alerts of abnormal conditions, contingency analysis, and recommended switching schemes for load balancing or outage impact minimization.

Integration of the ADMS with the Grid Modernization Phase 1 deployments of advanced meters, MDMS, and the telecom network 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 sensors on the Field Devices can identify an outage in a specific location on 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 devices and systems, including MDMS, geographic information system ("GIS"), and SAP. The ADMS can then analyze available advanced meter and Field Device 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. Switching configurations are then recommended by the ADMS FLISR module to minimize the number of customers impacted by the outage. This power-characteristic data flow information enables improved situational awareness for Grid Operators while also providing grid planners more data and confidence to integrate more DG.

Similarly, both advanced meters and grid sensors can identify voltage issues on a distribution feeder. In this instance, the ADMS can be used to coordinate distribution controls to adjust voltage on that feeder. Secondary VAR controllers and customer-owned advanced inverters can also detect voltage issues and autonomously make VAR adjustments (with settings managed by the standard interconnection Rule 14H and the participating customers' energy options),[7,8] while load tap changers and phase rebalancing schemes can be enabled by the ADMS.

Integration with the DEMS will afford Grid Operators with the status, availability, and control of customer-sited DERs, including DG, storage, controllable loads, and electric vehicles, which will provide Grid Operators with a wider array of tools to address issues uncovered with the enhanced situational awareness described above.

The ADMS will also interact with other operational and corporate systems to provide context to the stream of data. For example, the ADMS will integrate with DEMS[9] and each Company's existing Energy Management System ("EMS") to coordinate DER commands and dispatch. It will further integrate with the Companies' existing systems, including:

- SAP work orders to facilitate outage restoration processes;

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[7] See Standard Interconnection Rule 14H: https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rules/14.pdf

[8] 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").

[9] The DEMS is the name of the product that was approved in the DRMS docket. As the Commission recognized with D&O 36476, the line between DR and DER is nuanced from a policy and program perspective. Similarly, the differentiation between the functions associated with the management software capabilities is nuanced. For the purposes of the Companies' selected architecture, we will be discussing things in terms of DEMS and ADMS. The industry terms of DRMS and DERMS do not comport neatly with the Companies' unique and industry-leading vision wherein customer-cited resources will be relied upon for routine grid operation.

- SAP Customer Information System (CIS) and Geographic Information System (GIS) for the context about where DER options are enabled. This is required for greater context around decision making, faster outage recovery, and load characteristic information;
- Phase 1 software systems (telecommunications, meter head-end, and MDMS) to maximize the value of the outage and power characteristic information from the advanced meters.

The installation of the MDMS creates an immediate need for a data historian and the ADMS implementation (with Commission approval) will also require a standardized time-series data historian for Hawaiian Electric, Hawaii Electric Light and Maui Electric. The data historian will then become the system of record for much of the engineering and planning data utilized for analytics as discussed in the GMS and described in this application. While initially identified with Phase 3 of grid modernization implementation, the MDMS go-live necessitates inclusion of the data historian in Phase 2. Therefore, the ADMS Project includes the purchase of an enterprise license to standardize a time-series data historian. Currently Hawaiian Electric utilizes a data historian for both Power Supply and System Operation. This data along with the integrated visualization and analytics tools provides operational data which is used by the control room operators, heat rate data for engineers at the power plants on Oahu, weather variable information to the System Operation dispatchers, and SCADA data to generation, transmission and distribution planners for their analysis and modeling. Each data point that is stored and each calculated point in the system is called a tag and tags are purchased in increments (i.e., 1,000 tags, 10,000 tags, 100,000 tags). Currently there is a data historian Server at the Kahe power plant, the Waiau power plant, the CIP power plant and at Oahu System Operation. Hawaiian Electric purchases each server on a server by server basis. An enterprise license structure to standardize a time-series data historian was reviewed and compared against purchasing individual servers and tag increments. Under the existing purchase structure, tags are purchased under a capital project for new substations and power plants and any increases in tags for existing systems already in place are purchased under O&M. An enterprise structure would allow the Companies to pay a one-time perpetual license fee and an annual maintenance fee and allow the Companies to set up an unlimited amount of servers across the Company including for Hawaiʻi Electric Light and Maui Electric and receive an unlimited amount of data points. The comparison showed that purchasing an enterprise license would be less expensive than continuing to purchase tags and servers individually for each new substation, power plant, or large system. An enterprise license allows for flexibility in expanding a time-series database to Maui Electric and Hawaiʻi Electric Light for its ADMS installation.

As articulated throughout this Application, the Field Devices under consideration are selected to meet various needs.

- Where hosting capacity is limited and voltage profiles fluctuate dynamically, secondary Var controllers will be targeted for installation.
- Where enhanced system flexibility is required, intelligent switches with appropriate capabilities will targeted for installation.

- Where situational awareness is required, line sensors and RFIs will be targeted for installation.
- Where there is overlap in needs among DER integration, reliability, resilience, wildfire risk mitigation, and protection as is the case throughout much of our system, engineers will design an optimized circuit-specific solution.

3. Need

The Companies understand the need to coordinate 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. As detailed in the Phase 1 Application, the platform developed and deployed as part of the GMS will enable a grid that can reliably and safely operate with increasing levels of variable renewable resources (as described in the PSIP and pursued through IGP), 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. Collectively, these plans and programs lay out a conceptual framework for the Companies to successfully innovate and achieve necessary enhancements while continuing to pursue advanced technologies that align with customers' needs and interests.

Modernizing Hawaiʻi'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, including requiring 100% of net electricity sales to be provided from renewable energy by the end of 2045.[10] Coupled with the highest penetration of customer-owned PV systems in the country,[11] the Companies' GMS implementation will build the platform to provide customers with improved service, tools and offerings while simultaneously achieving policy milestones.

The sequence of technology investment, starting with GMS Phase 1, leverages functionally mature technologies that are already deployed elsewhere in the industry, including an MDMS and the latest generation advanced meters and FAN.

The core DMS and the OMS component of the ADMS is also a relatively mature technology and Oʻahu has utilized an OMS for over 12 years. However, neither Maui Electric nor Hawaiʻi Electric Light have installed an OMS and this investment will significantly increase their outage response capabilities.

However, the ADMS concept of bringing the DMS, OMS and DERMS together as an interoperable platform is a relatively new concept, with the industry putting significant research and development effort into the DERMS component. Hawaiʻi's need for a DERMS is evident

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[10] See Hawaiʻi State Energy Office, Grid Modernization, Renewable Portfolio Standard (RPS) targets, available at http://energy.hawaii.gov/renewable-energy/grid-modernization.

[11] 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.

given the already high level of customer DER interconnected on the island grids and the introduction of new DR programs. As a result, the Companies' DEMS implementation and this requested ADMS implementation are among those leading the nation.

With respect to Field Devices, each is a mature technology that have been deployed at varying levels across the industry. In fact, the Companies have tested and deployed in pilot form each of these devices in limited quantities already. These devices are proven to meet the requirements and design specifications.

According to the NC Clean Energy Technology Center's 50 States of Grid Modernization report,[12] most states are pursuing grid modernization actions (see Figure 2), with many moving from the policy, studies, and planning stage to deployment (see Figure 3). Due to Hawai'i's existing adoption of distributed photovoltaic generation (DG-PV) combined with the Hawai'i RPS goals as well as the fact that the Hawaiian islands are not interconnected with electric transmission lines, the need for grid modernization is arguably greatest in Hawai'i.

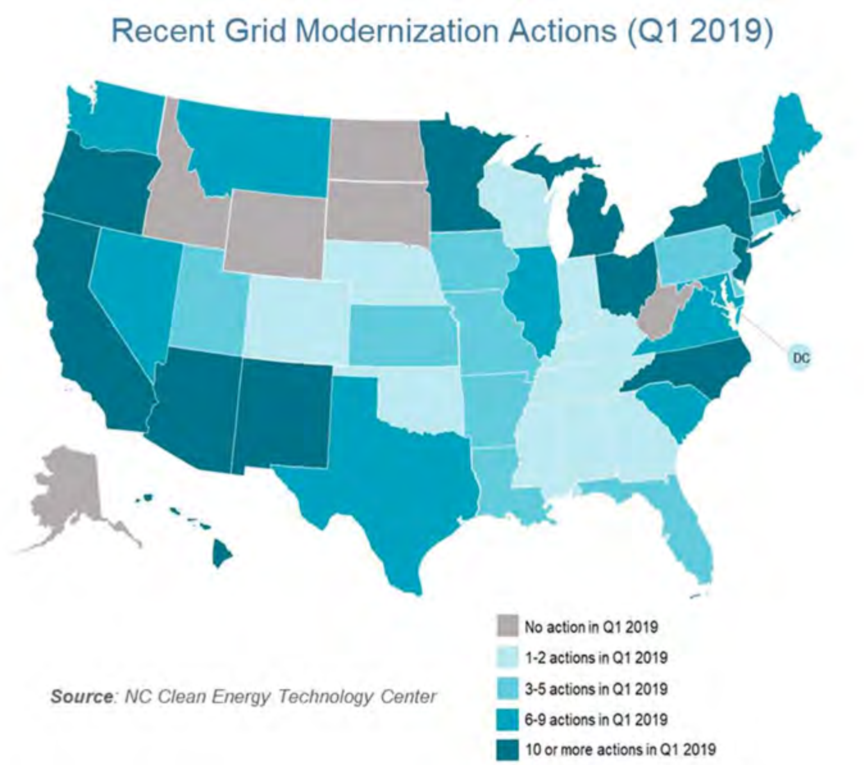

Figure 2

[12] NC Clean Energy Technology Center, *50 States of Grid Modernization Q4 2018 & 2018 Annual Review* (Feb. 2019), available at https://nccleantech.ncsu.edu/wp-content/uploads/2019/02/Q42018-GridMod-Exec-Final2.pdf

Figure 3

The Phase 2 implementation is being pursued now because:

- ADMS functionality is needed to more effectively and confidently manage the distribution grid.
- Planners require the measurements and software tools to more accurately and quickly design the system to integrate and rely upon customer-sited PV.
- Field Devices can provide reliability and operational benefits now while supporting a renewable energy future and integrate with the ADMS to continue to enhance functionality.
- The vendor community and industry has begun to settle on a standardization of ADMS capabilities, such that the Companies are confident that the solutions will deliver stated capabilities and benefits.

As stated in D&O 34884 in Docket No. 2015-0411 (DRMS Application), the ADMS will facilitate the situational awareness required to make informed decisions about localized DR and DER. In D&O 34884, the Commission recognized that situational awareness is key: "As situational awareness is increasingly made available to HECO Grid Operators, the currently procured DEMS will rely on that awareness to maximize the locational value of DERs through targeted dispatch."[13]

More recently, D&O 36476 in Docket No. 2014-0192 (DER Policies) discussed the importance of implementation tools to executing the DER vision: "The success of integrating additional distributed energy resources onto the electric system is highly dependent on coordinating the design and implementation of new grid service programs."[14] Phase 2 will help the Companies to expand their distribution awareness and ultimately help them better coordinate a safe and reliable system for customers.

D. PHASE 2 COMPONENT SELECTION PROCESS

The Companies followed a best-practice Request for Proposals ("RFP") competitive process to select from the pool of existing ADMS commercial off-the-shelf software solutions. This RFP process was conducted by a cross-functional team at the Hawaiian Electric Companies (including Hawaiian Electric, Maui Electric, and Hawaiʻi Electric Light) and guided by an external consultant with subject matter expertise in the area of ADMS procurement and ADMS implementation. More specifically, the RFP process followed a formal methodology consisting of the following eleven main tasks:

- Identifying the future state operational needs and use cases[15] for an ADMS;
- Identifying the functional and technical requirements for each ADMS module;
- Reviewing and aligning the requirements with relevant Commission dockets;
- Creating a comprehensive RFP package of documents and issuing the RFP to vendors;
- Bidders conference and question and answer period with vendors;
- Prior to receiving bid responses, defining the decision criteria used for scoring the vendor bids;
- Collecting and scoring vendor RFP responses to short-listed vendors, using an objective methodology consisting of weighted priority evaluation factors;
- Preparing demonstration scripts for the onsite vendor demonstrations;
- Onsite vendor demonstrations and final selection, using a set of prescribed demonstration scripts, a subset of the Companies' GIS data, and test cases that aligned with key operational use cases; and
- Final vendor scoring, selection, and vendor notification.

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[13] D&O 34884 at 38.
[14] D&O 36476 at 23.
[15] Refer to Appendix A of this document for a listing and description of the Companies Use Cases.

The RFP process was conducted between the fall of 2018 and the summer of 2019. A detailed description of the RFP process and vendor scoring is provided in Exhibit E (*Procurement Process*) to the Application.

III. SCHEDULE/OPERATIONAL IMPACTS

A. IMPLEMENTATION ASSUMPTIONS

1. ADMS

The Companies identified a variety of potential ADMS implementation schedule scenarios driven by several factors – the installation complexity and change management learning curve of the new ADMS system, as well as the desired and/or dependency sequencing of ADMS module configurations across the Companies' service territories.

The Companies determined that a multi-release implementation schedule would be the most appropriate way to install and configure any new ADMS system. A multi-release implementation allows the Companies to break-up a complex ADMS implementation into manageable projects, which consider (1) the amount of distribution data and connectivity in the GIS, (2) implementing components of an ADMS beginning with more mature products, such as an OMS and then progressing to more advanced applications, and (3) training and change management for System Operation personnel. A multi-release implementation is also consistent with other utilities in the industry, such as SCE and PG&E.[16]

In summary, the Companies will begin their implementation with functionality such as OMS, which has been in practice for many years. The ADMS implementation then progresses to DMS, including distribution SCADA, in conjunction with Distribution Automation ("DA"), which then leads to the Advanced Applications, including analytic functions for forecasting, simulating, studying, and optimizing the impacts of different network switching configurations and loading conditions. In the Companies' implementation, integration of DEMS is included from the first release in order to provide some visibility and control of DER from a system-level view. Subsequent releases will provide more localized visibility and control until the last release, which will optimize the use of DER into grid operations.

A multi-release approach ensures that the project allows for progressive data clean-up efforts in the Geographic Information System ("GIS"). ADMS functions require a grid connectivity model from the distribution breaker to a circuit down to the transformer connected to a circuit and then a customer connected to the transformer. In the case of O'ahu, GIS data includes all of this information down to the customer because O'ahu has an existing OMS. Maui Electric and Hawai'i Electric Light do not currently have customers mapped to distribution transformers. As the advanced analytic functions of an ADMS are enabled, phasing and conductor sizing is also required in the GIS distribution network model. Also, in order to enable

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[16] Utility Dive, "PG&E may answer the billion dollar grid modernization question." August 26, 2019: https://www.utilitydive.com/news/pge-may-answer-the-billion-dollar-grid-modernization-question/561146/

the visibility of DER at a local level, accurate DER information, such as DER sizing, output, and type of DER (PV, battery, DR program, etc.), must be incorporated into the DEMS.

Finally, ADMS training for Grid Operators for the ADMS is a significant task. A tri-company ADMS implementation will require standardization of processes across all three Companies. However, successful utilization of modern technologies and systems will take more than just standardizing processes and operating procedures across our three operating service territories, but also standardizing “new” operator positions, required skills, learnings, and qualifications. Therefore, developing a new training curriculum and training programs (pre/post) implementation will ensure that efficiencies are attained as early as possible. Hawaiian Electric Grid Operators on Oʻahu are already exposed to managing outages using an OMS, but they will require a translation of how outages are managed from the existing vendor to the new ADMS vendor. The Maui Electric and Hawaiʻi Electric Light Grid Operators will require training on using an OMS to transition from a more manual outage management process, such as utilizing paper trouble tickets, spreadsheets, and paper maps to using software and electronic maps to manage outages. The training then progresses into how the Grid Operator will continue to utilize the existing EMS for central generation control and managing system-level conditions and the ADMS for localized distribution controls. System Operations is a 24/7 activity, with personnel managing the grid on all three shifts. Inserting training for the Grid Operators while staffing for normal and emergency operations will require a coordinated and flexible schedule. A well-trained staff will ensure proper utilization of the variety of features, and capabilities within an ADMS, as well as proper coordination with existing tools like EMS. Implementing the ADMS in a series of releases enables proper training at a pace that Grid Operators will be able to absorb, retain, and utilize. The Operator Training Simulator (“OTS”) is a “key” component and tool for initial and ongoing training to sustain operator competency with updated training content, most especially on rapidly evolving grids such as the Hawaiian Electric Companies. System Operation is taking a disciplined approach for training and has already invested in a “pre-implementation” Training Curriculum Roadmap in 2020 for Oahu and in 2021 for Maui and Hawaii. This training curriculum roadmap analysis is specific to ADMS functionality/complexity and thus focused around identifying training gaps for the required new skills and competencies.

The proposed releases for the ADMS project are outlined below.

- **Release 1 – Deploy Basic ADMS Features to all Companies and System-level DER Functions**
    - Basic OMS features – Replacement of the Hawaiian Electric OMS and installation of OMS on Maui Electric and Hawaiʻi Electric Light, including outage tickets, outage call handling, training simulator, and mobile client;

- Fault Location Analysis (FLA) – Ability to accept outage information from the Field Devices for the purposes of determining the location of an outage to customers;[17]
- Basic DMS features[18] – Distribution SCADA for Hawaiian Electric, switch order handling for Hawaiian Electric, load forecasting, power flow analytics, and study mode;
- Basic SCADA features via Inter-Control Center Protocol (ICCP) – telemetry-only (no controls) via one-way integrations from existing EMS at each Company;
- Basic demand response (DR) and DER) features – to dispatch demand-side flexibility programs via the existing DEMS; and
- Integration with other key enterprise applications – Geographic Information System (GIS), SAP, Advanced Metering/MDMS, DEMS, and Asset Management Systems.

- **Release 2 – Deploy Additional ADMS Features and Localized DER Functions to All Companies**
  - Advanced features include distribution state estimation (DSE), fault location isolation and service restoration (FLISR), and primary connected, utility-controlled DER;
  - Implementation of Distribution SCADA for telemetry and control of distribution Field Devices and DERs on the distribution primary side;
  - Additional SCADA integrations with EMS to receive transmission state estimator values and pass controls to EMS-managed devices and resources; and
  - Ability to monitor and adjust the real or reactive power injection of large DER; and
  - Integration with wind and solar forecasting services from UL Renewables.
- ***Release 3 – Deploy Advanced DA and Optimize DER Features for All Companies***
  - Advanced DA integration includes volt-var optimization (VVO) and advanced protection equipment coordination schemes;
  - Advanced DER integration includes forward-looking contingency analysis, predictive DER scheduling, and load-shedding algorithms;

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[17] Fault Location Analysis (FLA) was included in Release 2 in the original Grid Modernization Phase 2 ADMS application in September 2019. FLA was moved into Release 1 to improve fault analysis while utilizing distribution Field Device capabilities.
[18] Hawai‘i Electric Light's and Maui Electric's EMS contain distribution SCADA information down to the distribution circuit breaker. This will remain in the EMS.

- Additional integrations to field volt-var control devices, protection, and switching equipment; and
- Enhanced integration to DEMS to enable status, availability, and control of all customer-sited DERs, including active loads, distributed grid-connected photovoltaic ("DGPV") systems, battery controllers, and electric vehicle charging.

a. Evolving Capabilities

The capabilities of the ADMS itself will grow in multiple releases, but they will also grow as distribution Field Devices are deployed over time based on grid needs. The ADMS and Field Devices are increasingly important as more customers enroll in energy options, and additional initiatives are executed to achieve the 100% RPS goal. As the Phase 1 advanced meters are deployed to more customers, the capabilities of the ADMS, including the insight into DER performance, will expand to new areas. The insight gained from voltage and outage alerts will increase system visibility, providing data to inform distribution grid state estimation. Additionally, the aggregation of interval usage (kWh) and demand (kW) data from advanced meters will refine load forecasts and load profiles for more refined distribution planning, including hosting capacity calculations. While the MDMS serves as the system of record for meter data, the ADMS will receive alerts from advanced meters (including voltage and outage alerts) through the Phase 1 efforts. The ADMS is the system of record for distribution grid data and configuration. The ADMS will receive near real-time telemetry from distribution substation systems and system monitoring data from Field Devices to provide Grid Operators with more data, greater distribution visibility (beyond the substation), and ultimately combine for a state estimation of the distribution system.

2. Field Devices

As shown in the Schedule portion of both this Exhibit and the Main Application, Field Devices are planned to be implemented prior to the ADMS go-live. Those Field Devices will be outfitted with telecommunications capabilities. The Field Devices with telecommunication capabilities will then be integrated with the ADMS during implementation. The existing line sensor and SVCs also have LTE telecommunication integrated into the device with data going to a vendor portal. This data will be integrated into the ADMS through a vendor API (Application Programming Interface). The existing deployment of other Field Devices (RFIs, smart fuses, and reclosers) are a mixture of devices that are not capable of telecommunication, devices that are telecommunication capable but telecommunication has not been enabled, and devices that have telecommunication enabled. The devices with telecommunication enabled will be integrated with the ADMS and a telecommunication retrofit plan will be developed for the capable of telecommunication.[19] Asset management of older equipment as well as Field Device

[19] The Phase 2 application does not include funding for Field Device telecommunication retrofit is not included in this application

deployment prioritization based on grid needs will then determine the replacement and upgrade of the Field Devices without telecommunication capabilities.

In order to install a Field Device on a utility pole, engineering must review the structural integrity of the pole to ensure it can support the additional weight and windage of the equipment. The Companies have found that utility poles often need to be replaced in order to support reclosers and other Field Devices. The cost for pole replacement is not included in this Phase 2 application, but the necessary pole replacements will be coordinated with asset management in order to replace poles prior to or in conjunction with Field Device deployment. This pole replacement also aligns with a key resilience strategy for the Companies to ensure that distribution poles that support critical equipment meet the latest engineering standards. The Companies' wooden pole infrastructure is comprised of both new and aging poles.[20] To ensure faster recovery from major events, critical field equipment will be placed on poles that meet modern standards for withstanding major weather events.

The Field Device quantities and associated costs contained herein represent a variety of assumptions, including the quantity of 3 phase and single-phase devices. These different types of devices will be used for different reasons at different locations on the distribution system. As the Companies' detailed circuit-specific designs are engineered, the ratios of Field Devices on the circuit may shift, but so may the proportions of 3 phase and single-phase devices. The deployment approach also incorporates ramping up the purchase and deployment of Field Devices over a three-year period with the fourth year achieving the most deployments and a fifth-year reduction in deployment quantity. Finally, as detailed in the Main Application, the Companies have utilized a learning curve to capture engineering efficiencies gathered through the programmatic deployment at the volume considered to support the GMS vision. The net result is that the total labor required to deploy each type of device decreases as more of that device is deployed. This approach is consistent with ramping up a production line to support production of a new product.

B. IMPLEMENTATION SCHEDULE

1. ADMS

Pending regulatory approval, the ADMS implementation project is expected to take four and a half years, as reflected in Figure 4. The vendors were asked to submit licensing and configuration bids based on this implementation schedule assumption.

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[20] See GMS at 27

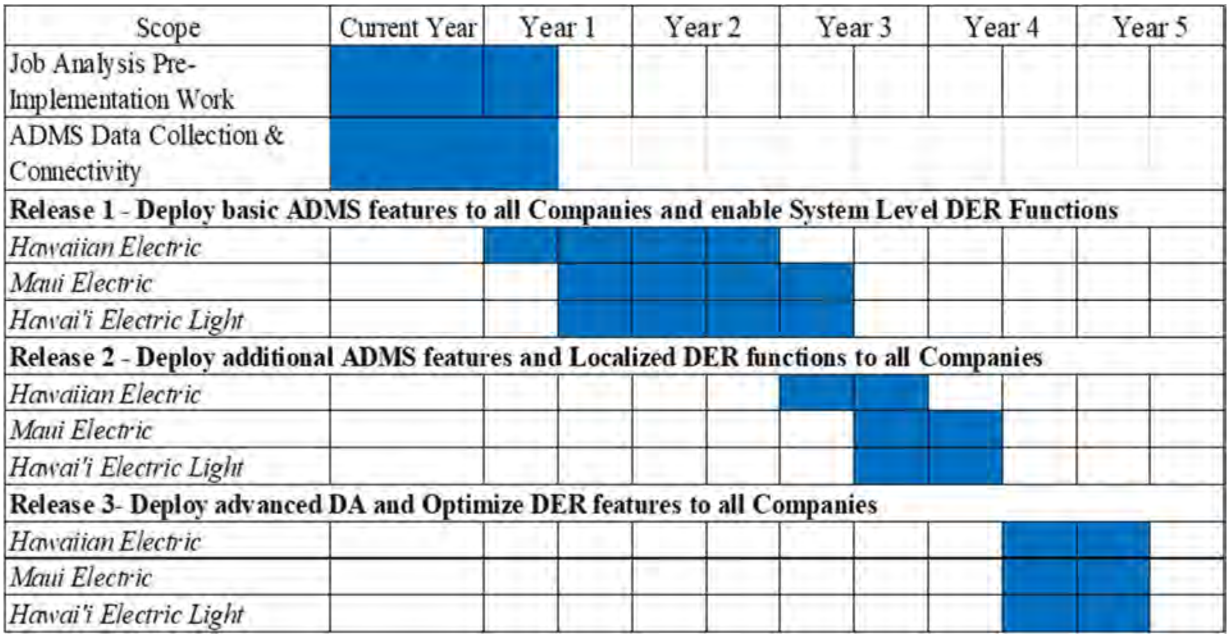

Figure 4 ADMS Implementation Schedule

2. <u>Field Device</u>

As Table 4 in the Application illustrates, the Companies plan to initiate Field Device deployment as soon as Commission approval is received. The Field Devices provide immediate benefits, even before integration with the ADMS. SVCs can act autonomously, mitigating voltage issues caused by DER where they occur. Line Sensors and RFIs will provide data that can be used in planning studies, such as hosting capacity analysis. Intelligent Switches (reclosers and smart fuses) can provide fault detection autonomously, limiting the quantity of customers affected by persistent outage conditions, and potentially clearing temporary outage conditions without the need to send a field crew to the locations. Each of these is possible before integration with the ADMS, but the integration is vital to providing the grid operator with needed field information and control, such as intelligent switch status and reconfiguration, to operate the system.

The proposed Field Device implementation schedule reflects current estimates for identified needs. The Companies teamed with Siemens to develop a Field Device strategy that focuses on voltage management to improve the quality of service for our customers (See Exhibit K *Siemens Field Device Strategy*). Separately, other field devices were identified by the Companies to support reliability improvement, wildfire risk mitigation, and protection enhancements and coordination. These deployments are currently focused on addressing priority circuits (worst performing, higher temporary fault history, wildfire risk, protection coordination issues, and other factors). As the grid continues to change, the Companies expect that the Field Device deployment plan will evolve and be refined during the five-year period to address the changing needs of the grid. The Field Device implementation schedule currently represents 45% of the distribution Field Device quantities needed. This allows the Companies to align with Commission-approved GMS conceptual budget while still allowing the Companies to take a big step towards the realizing the articulated GMS vision.

Pending regulatory approval, the Field Device implementation project spread across five years, as reflected in Figure 5 through 8.

Hawaiian Electric Companies	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total**
Recloser	2	6	10	12	9	39
Smart Fuse	22	66	110	132	110	440
RFI	12	36	60	71	59	238
SVC	32	96	160	192	161	641
Line Sensor	83	250	417	500	416	1666
Grand Total	151	454	757	907	755	3024

Figure 5 Consolidated Field Device Implementation Schedule

Hawaiian Electric	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total**
Recloser	1	4	6	7	5	**23**
Smart Fuse	16	47	79	94	80	**316**
RFI	0	2	3	4	4	**13**
SVC	17	50	84	101	85	**337**
Line Sensor	55	165	273	328	272	**1093**
Sub-Total	**89**	**268**	**445**	**534**	**446**	**1782**

Figure 6 Hawaiian Electric Field Device Implementation Schedule

Hawai`i Electric Light	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total**
Recloser	0	1	2	3	2	**8**
Smart Fuse	1	5	7	9	7	**29**
RFI	10	29	48	57	47	**191**
SVC	0	0	0	0	0	**0**
Line Sensor	19	57	96	115	95	**382**
Sub-Total	**30**	**92**	**153**	**184**	**151**	**610**

Figure 7 Hawai'i Electric Light Field Device Implementation Schedule

Maui Electric	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total**
Recloser	1	1	2	2	2	**8**
Smart Fuse	5	14	24	29	23	**95**
RFI	2	5	9	10	8	**34**
SVC	15	46	76	91	76	**304**
Line Sensor	9	28	48	57	49	**191**
Sub-Total	**32**	**94**	**159**	**189**	**158**	**632**

Figure 8 Hawaiian Electric Field Device Implementation Schedule

C. DEPLOYMENT APPROACH

1. ADMS

The Companies are assuming a decentralized approach for production operations, where each island control room will have its own ADMS servers with direct communications to local Field Devices. Non-production servers used for development, testing, and training will be centralized to reduce deployment and support costs. There are significant operational risks and ancillary costs associated with *centralizing* a mission-critical system like ADMS. The predominant risk is loss of interisland telecommunications, especially in a disaster storm or contingency situation. Grid Operators in the island control rooms must be able to reliably access the ADMS application server, and the ADMS SCADA module must be able to reliably communicate with local Field Devices on the islands. Therefore, for this reason, the Companies are proceeding with a hybrid approach that decentralizes the critical production operations while centralizing non-production servers.

Generally, the Companies have a strategic objective to standardize and centralize technology systems wherever possible in the interest of reducing information technology ("IT") and operational technology (OT) investment and support costs. For example, by standardizing a single ADMS solution vendor, the Companies anticipate realization of economies of scale in contracting, customizing, integrating, and maintaining the ADMS platform. Other alternatives would include integrating a new ADMS with the existing OMS for O'ahu and deploying an ADMS with OMS capability to Hawai'i Electric Light and Maui Electric. This would require two different OMS model build processes, and additional integration of a new ADMS to an existing OMS for O'ahu and continued licensing of a separate OMS for O'ahu, whereas the ADMS for Hawai'i Electric Light and Maui Electric would include an OMS with the same vendor. Thus, for this project, the Companies are standardizing on a single ADMS vendor, integrating the two existing EMS (Hawaiian Electric has a different EMS from Hawai'i Electric Light and Maui Electric) vendors to a single ADMS vendor that can provide OMS, DMS, and Advanced Applications for all three Companies.

2. Field Devices

Please refer to Exhibit A (*Grid Modernization Strategy Working Plan*) Section II.B. for details on the Field Device deployment approach.

IV. BENEFITS

The goal of implementing the ADMS and Field Devices is to provide greater visibility, control, and optimization of the distribution system for more reliable operations of a two-way grid with increased variable renewable and distributed energy resources ("DER"). Additionally, the solutions will improve resilience by allowing Grid Operators to quickly adapt to changing grid conditions and rapidly recover following power outages and disruptions by enhancing situational awareness and assisting in restoration triage to recover from events faster. The existing outage management processes will also be modernized to leverage ADMS reporting and automation features that improve customer communications, incident response, and operational efficiency.

The benefits of the ADMS and Field Devices can be summarized in three broad categories:

- Enable Customer Energy Options while advancing Clean Energy Goals
- Improve System Reliability and Customer Communications
- Enhance Operational Resiliency and Efficiency

These benefits are further explored in the following sections. As was discussed with respect to Phase 1, it is impracticable to aggregate GMS implementation benefits for use in a traditional benefit-cost 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. Because the ADMS is directly traceable to operational decision making, there may be an urge to characterize its benefits solely in the context of improved system and operational performance. As is laid out in the sections that follow, the value derived from Phase 2 includes improved situational awareness with distributed and variable renewable resources, power quality (voltage) control, safety, outage response, and improved customer satisfaction as a result of the other benefits listed. Each of these, and the trajectory of the Companies' IGP portfolio, must be considered in the evaluation of this application.

A. 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 Table 3, reproduced below.[21]

Table 3 Expenditure Categories and Evaluation Methodologies

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.

As illustrated in Table 8 of the GMS,[22] the Phase 2 components all fall within both the Standards and Safety Compliance and Policy Compliance categories. The lowest reasonable cost evaluation methodology is applicable to both of these expenditure categories.

As described in Exhibit E (*Procurement Process*), the Companies issued an RFP for the ADMS and the RFPs were developed and evaluated in the context of the GMS and the Companies' broader initiatives. The evaluation of the RFPs included vendor demonstrations and assessment to ensure the solution proposed is consistent with the GMS and will fulfill expectations as the Companies' needs grow. The technology is scalable and compatible with planned investments and architectures, which minimizes risks of stranded investments. Similarly, the Field Devices were procured using the Companies' standard processes, which solicit bids from multiple vendors to meet defined needs. Therefore, the solutions obtained

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[21] See GMS, Section 4.2 (Cost-Effectiveness Framework).
[22] See GMS at 107.

through this competitive procurement process will satisfy the Companies' technology needs (aligned to customer and policy objectives) at the lowest reasonable cost.

Importantly, as noted in the GMS, the need for a new holistic evaluation framework has also been recognized in other jurisdictions addressing grid modernization.[23] The Companies highlighted the work of the California Public Utilities Commission ("CPUC") extensively in the Phase 1 Application.[24] The CPUC ultimately issued its final Decision 18-03-023 in March 2018.[25] In that decision, the CPUC examined the four potential options for evaluating the cost-effectiveness of proposed grid modernization investments that were available.

The CPUC decision is complementary 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 and societal benefit-cost, and real option analysis approaches for grid modernization investments.[26]

This approach is also consistent with the IGP process, which is considering a full range of options to 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, Community-Based Renewable Energy ("CBRE"), Electrification of Transportation ("EoT"), and ongoing grid modernization projects.

B. CUSTOMER CHOICE AND CLEAN ENERGY

Legislative and regulatory direction has encouraged customer energy options in Hawai‘i, including utility and aggregator options with electric system benefits identified by the Commission, and has enabled progression toward clean energy goals and greenhouse gas reductions. 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

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

[24] See Docket No. 2018-0141, *Application of Hawaiian Electric Company, Inc., Hawai`i Electric Light Company, Inc., and Maui Electric Company, Limited* in Exhibit B at 21.

[25] 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.

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

in consumption and energy services, and enhances grid safety, security, reliability, and resilience."[27]

1. Two-Way Grid Visibility

The Phase 2 suite of technologies is critical to the continued addition of DERs with variable and two-way power flows while maintaining system reliability. The ADMS, in conjunction with Field Devices and Phase 1 advanced meters, will provide operational visibility, monitoring, and analytics that can facilitate safe, reliable operation with a large amount of energy sources on the distribution system, including potential for reverse power flows (power flowing from the distribution system into the transmission system). The ADMS will combine SCADA (telemetry data) with a geospatial electrical network connectivity model that contains grid assets (physical data) and electrical network details (connectivity data) to accurately calculate real-time power flows. ADMS analytic tools such as Distribution State Estimation and Power Flow Engine will allow Grid Operators to estimate the voltages and currents in the system where no direct telemetry exists. However, these estimates are enhanced by increasing measurement locations. ADMS forecasting and study tools can help estimate and potentially avoid future congestion and violation issues. ADMS switching, tagging, and lockout features will help ensure that maintenance and restoration activities are done safely.

The Companies are currently managing the bulk power system without visibility of or control over for the vast majority of distribution resources or the operating state of the distribution network. There are limited tools available, and primarily manual processes are used to operate the distribution system with its unprecedented levels of renewable penetration and widespread reverse power flows. The distributed resources currently have substantial impact on both the distribution system and the bulk grid. This lack of visibility and control over such a major component of the total grid energy is unsustainable. Modernization of the Companies' control rooms is required to support reliable and safe operation of the grid with continued renewable growth on the islands.

2. Coordination of Grid Edge Services

The ADMS will be the coordination hub of a distributed, layered architecture approach for grid management, as presented in the GMS, where the ADMS is supporting the Utility Distribution Operator role.[28] The ADMS, in coordination with the DEMS, would be substituted for the "Utility Distribution Operator" in Figure 9.

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[27] See Docket No. 2017-0226, D&O 35268, issued February 7, 2018, at 26.
[28] GMS at 20.

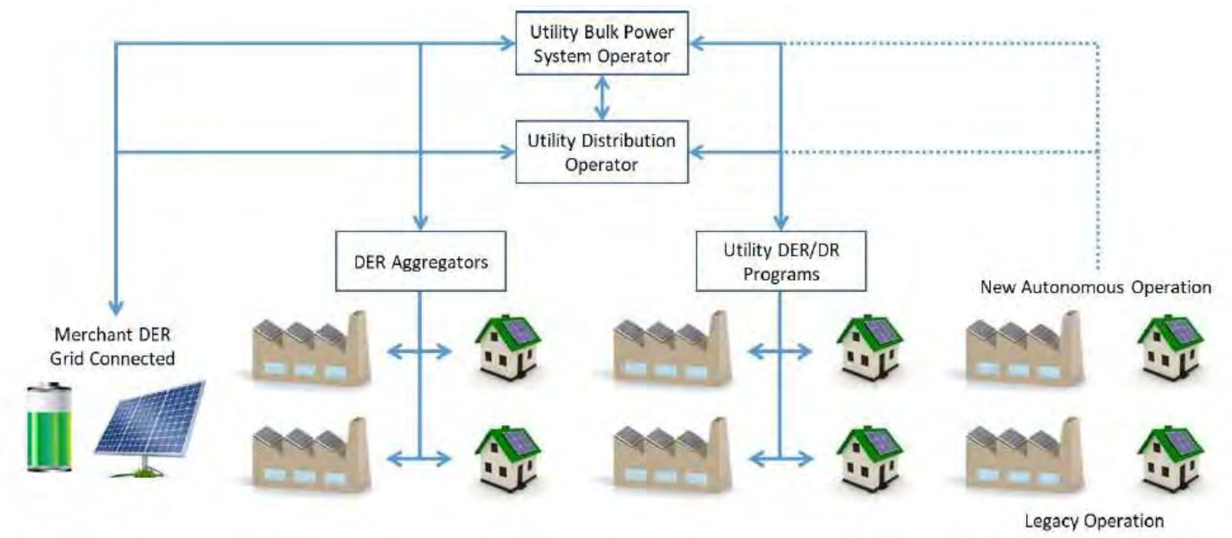

Figure 9 Distributed, Layered Approach for DER

The coordination framework involves managing the operation of grid-connected DER (both controllable systems and autonomously controlled systems) with distribution and transmission systems, as well as grid-scale generation. A layered approach allows coordinated management of the complex security and control interfaces with DER aggregators connected to the DEMS, which participates in specific customer energy options programs and tariffs, and it enables the flexibility to interface with customer systems that already exist, as well as new ones that will be added over time. Without proper coordination, managing this level of complexity across multiple parties will be problematic.

The future state of operations will include the existing EMS for monitoring and controlling system-level components and the ADMS, which will focus on the distribution system. Both of these systems will integrate to behind the meter resources using utility DR and DER demand-side flexibility programs for both bulk system grid services and local distribution grid services.

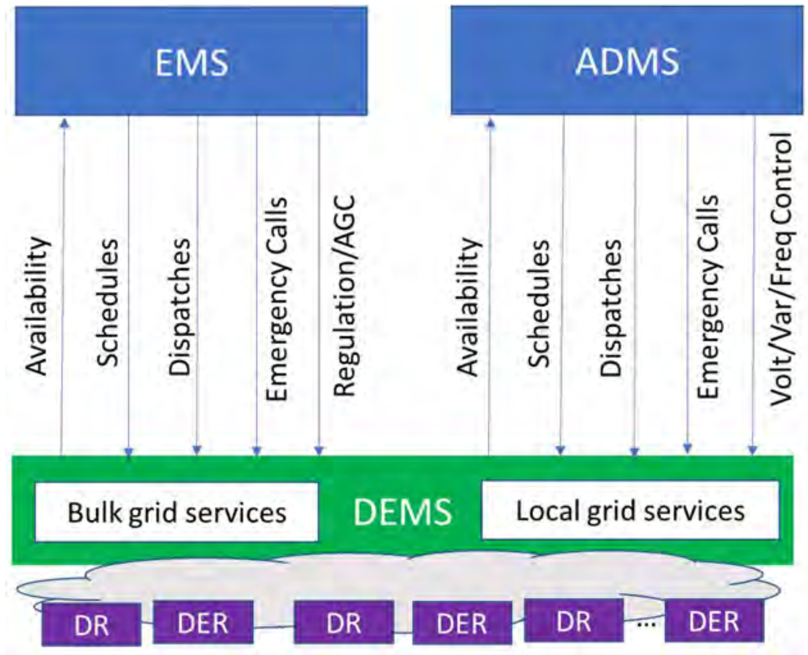

Figure 10 Future State Technical Architecture

The Companies have already made an investment in a DEMS system to enroll and manage demand-side DR/DER resources in incentive programs used for bulk system–level interruptible capacity and ancillary services. The EMS will integrate with the DEMS to dispatch these bulk system grid services. The ADMS will integrate with the DEMS to dispatch demand-side DR/DER flexibility to be used for distribution-level local grid services, distribution network capacity, power quality, and highly surgical ancillary services. The ADMS and DEMS will also interact to ascertain forecasting from distributed assets for inclusion into the load forecasting and advanced power flow forecasting.

3. <u>Non-wires Alternative for Clean Energy Objectives</u>

Phase 2 is essential to unlocking additional renewable capacity through intelligent software and to deferring capital-intensive wired-based grid upgrades driven by edge-of-grid resources. The ADMS enables non-wires alternative ("NWA") solutions through various strategies that can forecast network congestion and dispatch NWA in coordination with the DEMS to reduce stresses on aging equipment and proactively mitigate violations that can instigate protection faults. The ADMS-enabled strategies include network reconfiguration, VVO, DR, and DER control to actively manage local power balance and quality. The ADMS helps Grid Operators predict where stresses or faults may occur, select from the set of available options, and automatically reconfigure the network (using intelligent switches) or utilize demand-side resources. Meanwhile, Field Devices, such as the SVCs provide autonomous active voltage management at the grid edge, helping to smooth the voltage profile and allowing the ADMS to coordinate circuit-level adjustments.

The ADMS is an integral part of the overall Grid Modernization Strategy. It is the central control system that provides grid edge visibility, control, and optimization of DERs and field automation. Without the investment in ADMS, customer energy options will be limited, and their respective benefits will not be fully realized.

The ADMS functions not only as the central real-time distribution visibility and control engine, but its capabilities include a planning mode and improved distribution system modeling. These capabilities will assist the Companies in identifying requisite system upgrades and improving the accuracy of the Companies' existing modeling capabilities. The benefit of this is two-fold: (1) more confidently incorporating DER and (2) identifying opportunities for non-wires alternatives, as is being discussed in IGP, which could defer traditional infrastructure upgrades and could unlock a suite of additional capabilities. The Companies are investigating NWAs, and the implementation of these alternatives coincides with the anticipated timing of an ADMS implementation. Ultimately, the additional NWA capabilities will improve the overall system capability to incorporate DER, creating a system that can meet the State's RPS.

C. SYSTEM RELIABILITY AND CUSTOMER COMMUNICATIONS

1. Reduce Outage Restoration Time

The primary purpose and benefit for implementing the OMS module of an ADMS is to reduce outage restoration time, as measured by the System Average Interruption Duration Index ("SAIDI") and Customer Average Interruption Duration Index ("CAIDI"). Improvements in SAIDI and CAIDI are achieved by improving the ability of the control room to identify the location and causes of faults, prioritizing outages based on customers affected, and optimizing the dispatch of field technicians. The Field Devices also help with SAIDI and CAIDI, both by limiting the number of customers affected through sectionalizing the circuit and by providing measurements to narrow the geography that field crews must cover to identify the broken equipment.

Phase 2 uses advanced analytics and measurements from the grid edge to further improve outage restoration times. For instance, Fault Location Analysis (FLA) can use impedance measurements and alarms from Remote Fault Interrupters (RFIs) to help pinpoint fault locations (and causes) and thus improve crew dispatch. Fault Location, Isolation, and Service Restoration (FLISR) can help create (and automatically perform) switching plans for distribution Grid Operators to execute in order to restore as many customers as possible by energizing them from alternate electrical paths. Eventually, when the ADMS is more operationally mature, some switching plans could transition from grid operator executed to automated switching controls. The Switch Order Management (SOM) and study features can also help reduce the customer impact of planned outages for system maintenance.

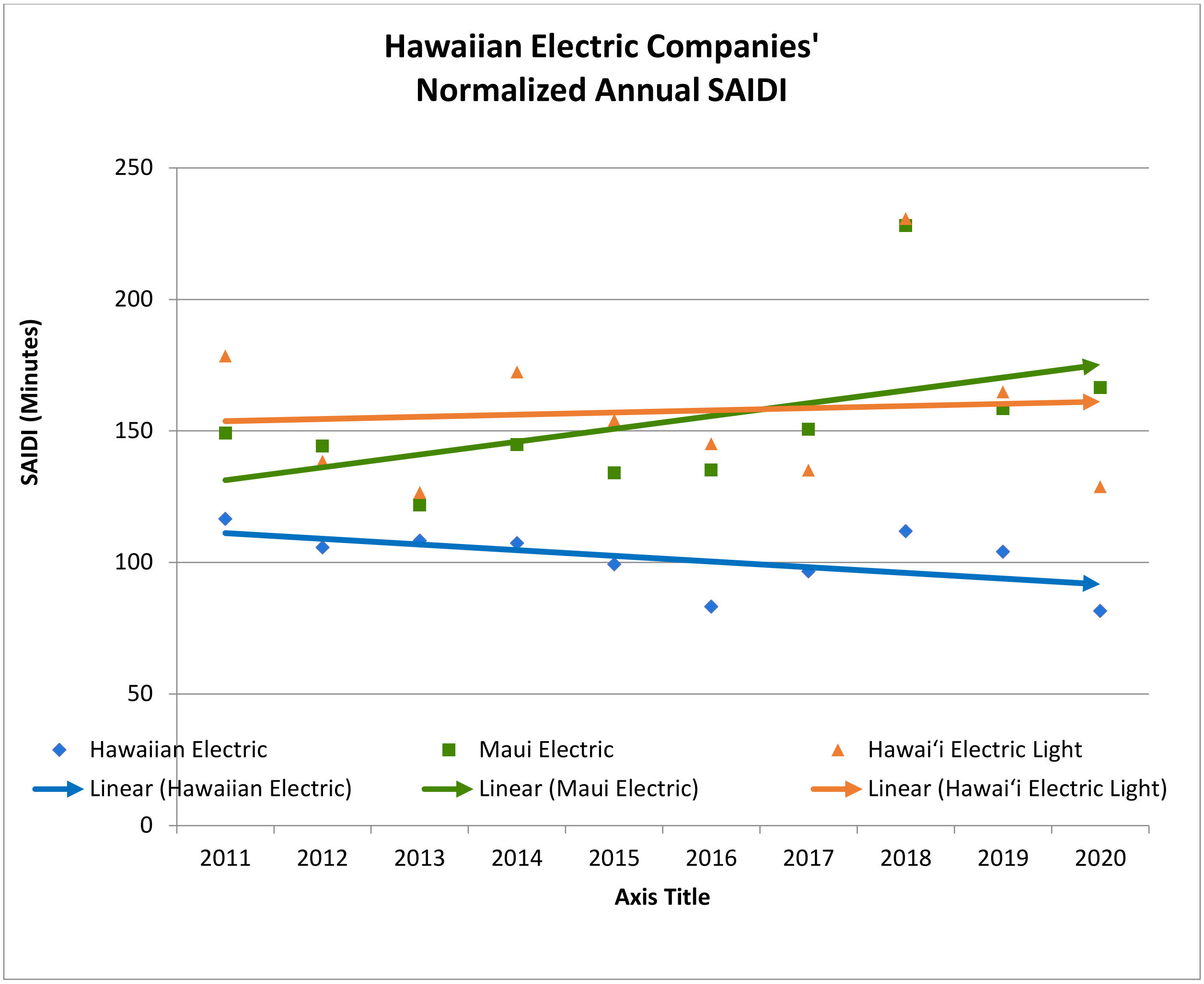

Figure 11 Normalized Annual SAIDI

The pace and realization of these benefits depend somewhat on the deployment and SCADA integration of DA Field Devices (e.g. Line Sensors, Remote Fault Indicators, Intelligent Switches, other Field Devices), and advanced metering, but the ADMS is the enabling technology that provides Grid Operators with visibility and control.

SAIDI Improvement Potential with FLA			
Forecasted SAIDI with proposed fault circuit indicators and 3 phase Smart Fuse			
	SAIDI		
	5-yr Avg	# of FCI/3 phase Smart Fuses	Forecasted SAIDI
Hawaiian Electric	95.5	76	94.9
Maui Electric	167.7	53	159.6
Hawai'i Electric Light	160.9	197	148.4

Note: What is shown is a simplified calculation with all other factors remaining the same. Many issues could impact the performance of FLA, including more than average turbulent weather conditions, conditions of equipment, labor issues and training, etc.

SAIDI Improvement Potential with FLISR			
Forecasted SAIDI with proposed reclosers and 3 phase Smart Fuses			
	SAIDI		
	5-yr Avg	# of Reclosers/3 phase Smart Fuses	Forecasted SAIDI
Hawaiian Electric	95.5	86	92.2
Maui Electric	167.7	27	161.1
Hawai'i Electric Light	160.9	14	158.9

Note: What is shown is a simplified calculation with all other factors remaining the same. Many issues could impact the performance of FLA, including more than average turbulent weather conditions, conditions of equipment, labor issues and training, etc.

Figure 12 Estimated SAIDI Savings with FLA and FLISR Implemented

Figure 12 displays a simplified calculation of the potential impact on SAIDI and SAIFI once the ADMS is deployed and all of the proposed Field Devices are installed (at the end of the 5 year plan). The Companies will deploy the ADMS and Field Devices over a 5-year period, thus the SAIDI and SAIFI improvements will be ramped up year by year as ADMS capabilities and Field Devices are deployed. There will also be combined benefits with some benefits overlapping. Thus, Figure 12 represents the estimated effects for FLA utilizing only the RFI and 3-phase smart fuses and estimated effects of FLISR assuming one recloser or one 3-phase smart fuse per circuit. In some cases, more than one recloser or more than one 3-phase smart fuse may be deployed per circuit, which could result in further improvements to SAIDI of that circuit and contribute to additional SAIFI.

Automating outage management processes with an ADMS will also have restoration operation benefits to the Companies. The savings are mostly in the form of improved staff productivity in the control room and field crews. When the ADMS is integrated with increased sensing from Field Devices, outage notifications from advanced metering (MDMS and Meter Head End), and SCADA to receive real-time field telemetry, the ADMS will help Grid Operators more quickly locate, assess, and triage outages with temporary restoration switch plans and crew dispatch instructions. The improved fault location, damage assessment, and partial customer restoration then allow for more precise and optimized field crew dispatching.

2. <u>Reduce Outage Frequency</u>

To a lesser extent, an ADMS can help reduce outage frequency, as measured by the System Average Interruption Frequency Index ("SAIFI"). Improvements in SAIFI are achieved mostly through FLISR and reclosing by restoring some customers more quickly and converting a percentage of outages into momentary interruptions.[30] ADMS is also an enabling technology to support various Active Network Management ("ANM"), Volt/VAR Optimization ("VVO"), DR, and DER strategies that can forecast and avoid network congestion that stresses aging equipment and violations that create protection faults.

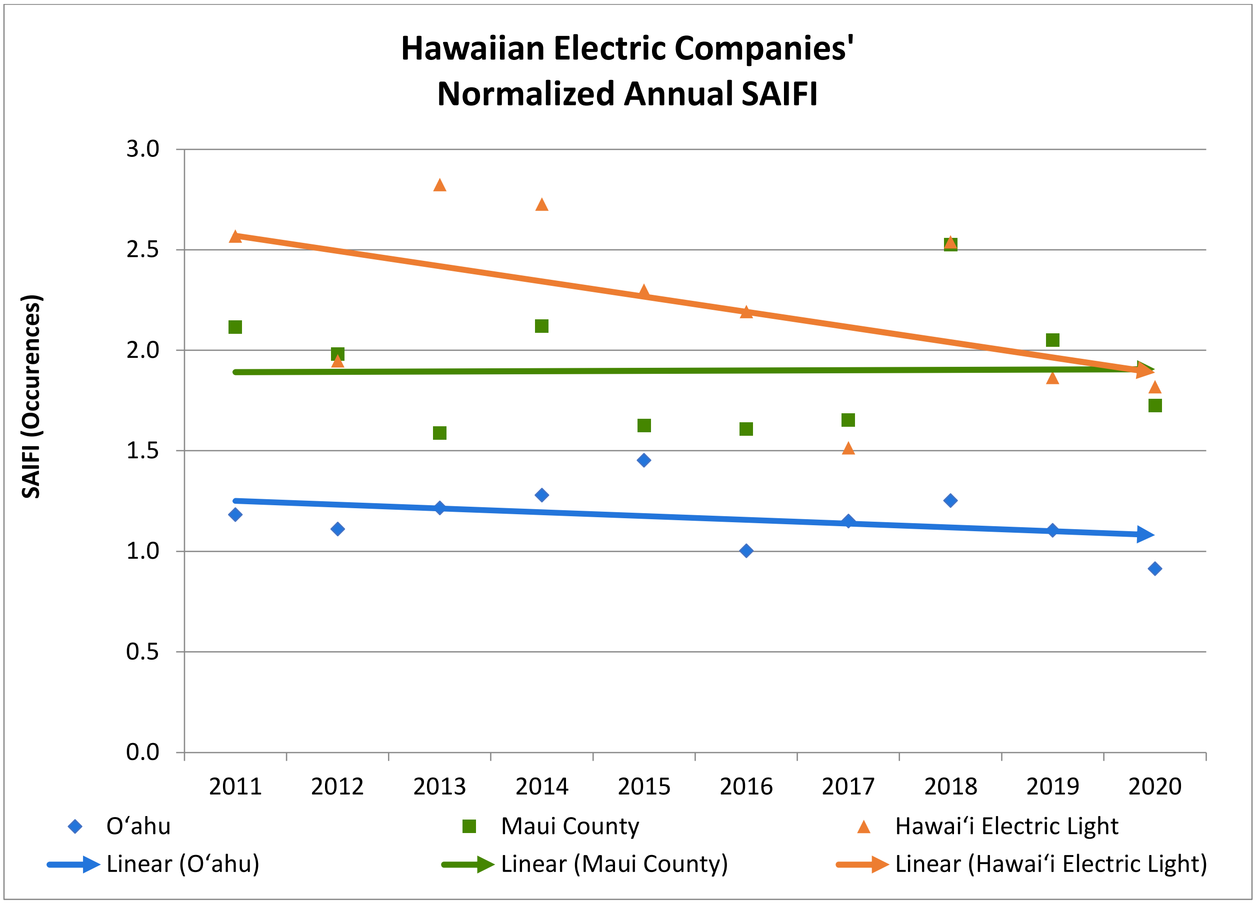

Figure 13

The pace and realization of benefits depend largely on the current SAIFI on each island (the opportunity for improvement) and the level of corresponding Field Device investment. For instance, a highly targeted investment in feeder automation at Maui Electric or Hawai'i Electric Light has a much larger effect on SAIFI than a larger investment at Hawaiian Electric.

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[30] Note this has the consequence of shifting SAIFI numbers into MAIFI - Momentary Average Interruption Frequency Index.

SAIFI Improvement Potential with FLISR			
Forecasted SAIFI with proposed fault circuit indicators and 3 phase Smart Fuses			
	SAIFI		
	5-yr Avg	# of FCI/3 phase Smart Fuses	Forecasted SAIFI
Hawaiian Electric	1.085	76.0	1.011
Maui Electric	1.913	53.0	1.770
Hawai'i Electric Light	1.986	197.0	1.923

Note: What is shown is a simplified calculation with all other factors remaining the same. Many issues could impact the performance of FLA, including more than average turbulent weather conditions, conditions of equipment, labor issues and training, etc.

Table 1

The Companies expect FLISR to deliver a 5%–20% reduction in SAIFI as supporting DA Field Devices are deployed and integrated. The cumulative SAIFI improvement potential of using ADMS to execute ANM strategies and the installation of Field Devices is more difficult to quantify and isolate from other factors but is estimated at 3-7% over the next 12 years. Table 1 is a simplified calculation to show potential impacts to SAIDI based on installing the proposed number of reclosers and 3 phase smart fuses at one per circuit. Actual results are dependent on factors such as weather conditions, rate of deployment of Field Devices, including the advanced meters, amount of Field Devices deployed per feeder, etc.

3. <u>Improved Value of Electric Service</u>

Reducing outage frequency and duration will have an economic benefit to island electricity customers. For instance, storm-related outages are estimated to cost U.S. customers an average of $25–$75 billion annually.[31] Outages impact factory operations, retail sales, office computers, entertainment, comfort, tourism, and even solar PV production. The value of improved electric service reliability accruing to customers in a geographic region can be estimated with the Department of Energy's ICE Calculator, which estimates the direct-to-customer benefits associated with utility reliability improvements.[32] The ICE Calculator estimates that decreases in SAIDI of 1% or 2% could result in increased customer value (of avoided outages), as shown in the tables below. The Companies do not have statistics or data to determine the costs of outages to our customers, thus the ICE Calculator was used here to provide an illustrative sample of what some of the cost impacts could be to our customers. It should be noted that the data utilized in the algorithms of the ICE Calculator are outdated and only included data from specific regions where a customer impact survey was conducted.

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[31] <u>See</u> LBNL, "Improving the Estimated Cost of Sustained Power Interruptions to Electricity Customers," June 2018.

[32] <u>See</u> https://icecalculator.com. The Interruption Cost Estimate (ICE) Calculator is an electric reliability planning tool developed by Lawrence Berkeley National Laboratory and Nexant, Inc. This tool is designed for electric reliability planners at utilities, government organizations, and other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States.

Value of Service Reliability Improvement (SAIDI)			
SAIDI sensitivity to FLISR example			
	SAIDI	# of FCI/3 phase Smart Fuses	
	5-yr Avg	Forecasted SAIDI	$k
Hawaiian Electric	95.5	94.9	921
Maui Electric	167.7	159.6	3,617
Hawai'i Electric Light	160.9	148.4	5,992
			10,530

Table 2

Value of Service Reliability Improvement (SAIFI)			
SAIFI improvements through FLISR			
	SAIFI	# of FCI/3 phase Smart Fuses	
	5-yr Avg	Forecasted SAIFI	$k
Hawaiian Electric	1.09	1.011	9,764
Maui Electric	1.91	1.770	5,514
Hawai'i Electric Light	1.99	1.923	2,747
			18,025

Table 3

Note that the ICE Calculator does not capture the nuances of how our customers value the grid, nor does it capture the system's increasing reliance on the distribution system as a point of interconnection for generation resources to meet system goals. The customer mix in Hawai‘i is different than the generic residential, commercial, and industrial profile mixes found in the ICE calculator. Moreover, when outages occur on distribution circuits that are exporting power due to oversupply of DER generation, those systems are taken offline, thus lowering the grid system's generation relative to demand.

4. <u>Improve Customer Satisfaction</u>

By implementing an ADMS, the Companies can better meet customer, media, and government expectations of more communication and detailed operations information during normal and emergency situations. Recent years have required frequent emergency incident response events due to tropical storm threats and volcanic eruption impacts, requiring the entire System Operations and Planning divisions to participate in coordinated emergency response and develop communications plans for resilience and restoration.

Hawai‘i Electric Light and Maui Electric do not currently have an OMS solution. This project will include the installation of an OMS, which will enable faster reporting of outage information and enable more informed restoration and incident response to large system disturbances, including coordination with external stakeholders in the community. This will also provide the basis for Hawai‘i Electric Light and Maui Electric to provide up-to-date customer communications. At present, outage information must be compiled and communicated manually after field inspections determine the nature and extent of outages. Hawaiian Electric's existing

OMS solution helps track calls and dispatch crews, but it does not provide the visibility necessary to immediately answer customer questions. This issue may be reflected in the Companies' customer satisfaction survey results.

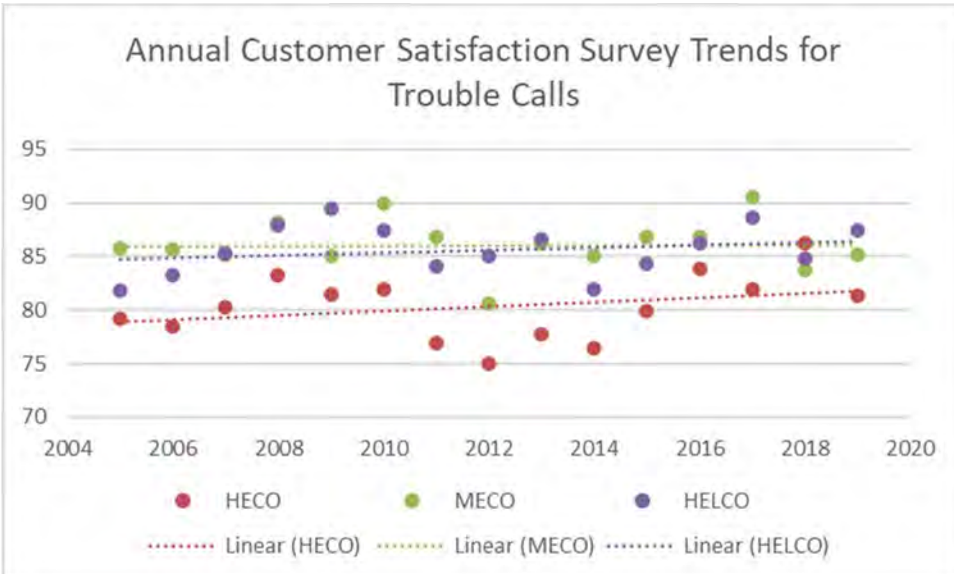

Figure 14

With an ADMS, the Companies will be able to keep customers better informed on system status, restoration times, and actions being taken by the utilities. Grid Operators will also be able to provide immediate answers to customers during regular trouble calls, facilitated by improved visibility of distribution grid conditions and open issues.

The ADMS will also be able to immediately leverage the investment in GIS to improve outage location and customer impact estimates. Once deployed and integrated with the advanced meters and other field sensors, the ADMS will be able to identify and locate outages before customers call. The long-term goal is to support outbound calls to customers with outage notifications and estimated time to restoration information. JD Power reports that proactive notification is a key factor in improving customer satisfaction.[33]

5. Improve Outage Reporting Accuracy

Replacing manual control room processes with an ADMS software solution typically results in more accurate operational reporting. Accurate reporting is critical to building confidence in customer communications and performance-based ratemaking. The current level of *inaccuracy* (and thus the potential for improvement) is difficult to quantify in advance. As an example, the current process relies on customer calls to establish an outage start time, so any

[33] See https://www.utilitydive.com/news/for-utility-customer-satisfaction-jd-power-says-communication-control-a/422800/

delays in reporting the outage would result in underestimating the total outage duration. Generally, the improvements in accuracy manifest in several areas – Estimated Time to Restoration ("ETR") reporting, Hosting Capacity ("HC") reporting, and SAIDI/SAIFI (and other reliability performance metrics) reporting.

The improvement in ETR reporting comes from improved mobile field communications, better damage assessments, and statistically derived crew and damage restoration estimates. The improvement in HC reporting comes from more accurate customer meter-transformer associations and better real-world power quality observations from the distribution grid edge. The improvement in accuracy of SAIDI, SAIFI, and similar reliability metrics comes from more accurate logging of outages times, customer calls, fault alarms, customers affected, and restoration times.

It is important to note that these improvements in reporting accuracy may appear as a temporary deterioration in performance once the ADMS goes into production. This is often due to the prior manual processes masking errors in the process or data, which are exposed and resolved as part of process automation. It may be necessary to adjust or normalize historical reporting to avoid a negative public perception of this side effect.

D. OPERATIONAL RESILIENCY AND EFFICIENCY

1. Enhanced Contingency Control

The ADMS will provide Grid Operators with improved visibility, control, and optimization of contingency situations and protection schemes. The ADMS Study and Powerflow functionality allows Grid Operators to analyze distribution grid-edge voltage support and to short-circuit current availability. It supports analysis of the impact of potential events. ADMS also provides a platform that can be used to integrate grid-tied storage batteries and local microgrids[34], which can then be incorporated into restoration and recovery plans. In general, the ADMS will support complex contingency analysis to include consideration of the distribution systems as smaller DER assets increasingly provide a majority of total grid energy.

2. Distributed Control Room Operations Flexibility & Efficiency

The selected ADMS has a modern distributed technology architecture that supports resiliency and flexibility in control room operations. The software allows for secure local and remote access if necessary. These features support resiliency through allowing secure remote access by authorized users for emergencies and emergency backup operations at alternate locations. The mobile features also provide improved situational awareness though enhanced field crew communications for real-time restoration triage, dispatching, and damage assessment.

[34] Additional ADMS functional modules may need to be purchased to achieve microgrid visibility and control.

3. Improved Disaster Recovery

The proposed ADMS deployment architecture includes built-in redundancy of mission-critical components for enhanced operational resiliency in the event of major natural disasters, computer failures, cyber intrusions, or telecom interruptions. This includes a highly available production server environment for the main control rooms, which supports physically separate disaster recovery environments for contingency operations. The ADMS project will help mitigate resiliency and reliability risks of the renewable energy future with a modern control room solution and architecture that is consistent with the increasing importance of grid-edge DER to overall system power supply and reliability.

The Field Devices will similarly unlock distribution system flexibility that will provide more disaster recovery options. The ADMS may identify opportunities to return power to half of customers on a given circuit, but the only way to provide power to half of the customer on a circuit is if there is a switch located there. In disaster situations, the remote controllability of intelligent switches will be vital as field crews prioritize rebuilds and other work.

4. Control Room Efficiencies

The ADMS will replace manual control room processes, i.e., outage tracking using MS Access database, manually performing load calculations for transferring loads, and using MS Word to create hold-off and switching orders, with software automated processes. The resulting work efficiencies will allow Grid Operators to focus on higher-value grid planning, monitoring, and optimization tasks. The software also helps reduce operator mistakes that can drive unplanned outages, aborted maintenance activities, or safety issues.

The new ADMS Training Simulator will facilitate Grid Operators through simulating events. Using a simulator reduces the learning curve time for new Grid Operators for the actions in response to various scenarios and conditions that would otherwise have to be experienced through real-time events. The ability to simulate both daily activities like maintenance switching and seasonal activities like storm restoration provides Grid Operators with more hands-on experience, allowing them to be more productive with the software and less likely to make operating errors during all activities.

Furthermore, the use of standardized ADMS software and common training tools will increase the Companies' ability to share operating lessons and resources across the islands. This will provide the ability to optimize staff skills and balance workloads.

5. Information Technology Efficiencies

The ADMS is a modern software solution for operating a modern grid. In addition to supporting efficiencies in the control room and field services, it is designed for efficient software maintenance, security and resiliency. The system will have automated diagnostics and logging on all its servers, databases, and applications to simplify system health monitoring and issue identification. It will also have user-accessible features for application configuration and administrative features for on-the-fly software upgrades to minimize the cost and downtime of changes.

By selecting a common ADMS solution for all the Companies, the islands will have similar control room software, equipment, and integration architecture. This will provide savings through scale economies of standardized vendor purchase agreements, training, configurations, customizations, integrations, support tools, security frameworks, and communications infrastructure. It will reduce the amount of duplicative work at different operating companies and improve cross-island leverage of technical training, development, and support staff.

The Companies will share development, testing, and training environments. The Companies also plan to share many production components while ensuring system high-availability during emergency conditions.

E. ALIGNMENT WITH PERFORMANCE BASED RATEMAKING

These benefits are consistent with the guiding principles, regulatory goals, and priority outcomes defined by the Commission in the recently published Performance-Based Ratemaking ("PBR") framework.[35]

The PBR guiding principles include:

- A customer-centric approach,
- Administrative efficiency, and
- Utility financial integrity.

The PBR regulatory goals and corresponding priority outcomes are as follows:

- Enhance Customer Experience
  - Affordability
  - Reliability
  - Interconnection Experience
  - Customer Engagement
- Improve Utility Performance
  - Cost Control
  - DER Asset Effectiveness
  - Grid Investment Efficiency
- Advance Societal Outcomes

[35] Docket 2018-0088.

- Capital Formation
- Customer Equity
- Greenhouse Gas Reduction
- Electrification of Transportation
- Resilience

The following table outlines how the ADMS and Field Device benefits align with the PBR framework.

	Enhance Customer Experience				Improve Utility Performance			Advance Societal Outcomes				
Benefits Breakdown	Affordability	Reliability	Interconnection experience	Customer engagement	Cost control	DER asset effectiveness	Grid investment efficiency	Capital formation	Customer equity	GHG reduction	Electrification of transport	Resilience
Customer Choice & Clean Energy												
Two-way grid visibility												
Coordination of grid edge services												
Non-wires alternative solution												
System Reliability & Communications												
Reduce outage restoration time												
Reduce outage frequency												
Improved value of electric service												
Improve customer satisfaction												
Improve outage reporting accuracy												
Improve restoration productivity												
Health, safety, and mortality												
Operational Resiliency & Efficiency												
Enhanced contingency control												
Distributed operations flexibility												
Improve disaster recovery												
Control room efficiencies												
Field service efficiencies												
Information technology efficiencies												

Table 4

V. EXPECTED INVESTMENT

A. PROJECT COST ESTIMATE

1. ADMS

The combined Capital, Deferred, and Expense Costs for the ADMS component of the GMS over its anticipated over a four and a half year implementation period are estimated at [redacted] million. This cost estimate aligns with the original conceptual cost estimate for Advanced Operation Systems identified in the August 2017 GMS.[36] However, the GMS conceptual budget did not include ongoing operations and maintenance ("O&M") expenses. The Companies will be requesting recovery of these costs via the EPRM mechanism until such costs are reflected in base rates established in the Companies' respective rate cases.

The implementation costs for the ADMS, as the components are placed into service, are broken down by utility and accounting treatment, as shown in Figure 15 and Figure 16.

Company	Account Group	Year 1	Year 2	Year 3	Year 4	Year 5	Subtotal
Hawaiian Electric	Capital	[redacted]					[redacted]
Hawaiian Electric	Deferred		[redacted]	[redacted]		[redacted]	[redacted]
Hawaiian Electric	Operations & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawai'i Electric Light	Capital	[redacted]					[redacted]
Hawai'i Electric Light	Deferred			[redacted]	[redacted]	[redacted]	[redacted]
Hawai'i Electric Light	Operations & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Maui Electric	Capital	[redacted]					[redacted]
Maui Electric	Deferred			[redacted]	[redacted]	[redacted]	[redacted]
Maui Electric	Operations & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Figure 15 – Implementation Costs by Company and by Year

[36] See GMS at 110, Table 9.

Company	Project	Year 1	Year 2	Year 3	Year 4	Year 5	Useful Life
Hawaiian Electric	Release 1 (Capital)	[redacted]					5
Hawaiian Electric	Release 1 (Deferred)		[redacted]				12
Hawaiian Electric	Release 2 (Deferred)			[redacted]			12
Hawaiian Electric	Release 3 (Deferred)					[redacted]	12
Hawaiian Electric	Annual O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	n/a
Hawai'i Electric Light	Release 1 (Capital)	[redacted]					5
Hawai'i Electric Light	Release 1 (Deferred)			[redacted]			12
Hawai'i Electric Light	Release 2 (Deferred)				[redacted]		12
Hawai'i Electric Light	Release 3 (Deferred)					[redacted]	12
Hawai'i Electric Light	Annual O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	n/a
Maui Electric	Release 1 (Capital)	[redacted]					5
Maui Electric	Release 1 (Deferred)			[redacted]			12
Maui Electric	Release 2 (Deferred)				[redacted]		12
Maui Electric	Release 3 (Deferred)					[redacted]	12
Maui Electric	Release 3 (O&M)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	n/a

Figure 16 – Implementation Cost by Component and by Year

The costs for each of the components are generally broken down into the following six cost categories: (1) internal labor, (2) materials, (3) outside services, (4) other (hardware); (5) overheads, and (6) allowance for funds used during construction ("AFUDC") and are displayed in Exhibit G (*Updated Project Costs*).

The internal labor cost category, which totals approximately [redacted] includes costs for any incremental resources that are required to support the project's deployment. Among other things, the new, 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 G (*Updated Project Costs*).

The outside services cost category, which totals approximately [redacted] includes costs for external vendor staff services to support both software development and related activities, provide training, and data migration. These costs consist of both consultants and the request for proposal ("RFP") awardee that has provided anticipated estimates on labor needs as part of the ADMS deployment and implementation period. The outside services cost category includes an enterprise license for a standardized time-series data historian of [redacted] (one-time license fee) and annual software maintenance fee of [redacted] as a deferred cost in Year 1 and an annual O&M cost of [redacted] in Years 2-5. This replaced costs previously filed in the original ADMS Application filing of [redacted] for hardware and [redacted] for data historian tag increments for Hawaiian Electric, Hawai'i Electric Light and Maui Electric. The deferred and O&M components are described in Exhibit C (*Accounting and Ratemaking Treatment*).

The "other" hardware cost category, which totals approximately [redacted] includes costs for computer hardware as described in Exhibit C (*Accounting and Ratemaking Treatment*).

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 of 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.

As discussed in Section III.C above, the Companies are proceeding with a hybrid approach that decentralizes the critical production operations, while centralizing non-production servers used for purposes such as development and testing. Therefore, there will be systems installed at each of the Companies, and there will also be centralized infrastructure shared by the Companies installed at Hawaiian Electric. As described in Exhibit C (*Accounting and Ratemaking Treatment*) to the Application, for the centralized systems, the costs will be allocated between the Companies with 70% recorded to Hawaiian Electric and 15% billed to each of Maui Electric and Hawai'i Electric Light. Otherwise, costs specific to each Company will be allocated 100% to the respective Company.

Training – Pre-Implementation Job Analysis

The Companies are placing an emphasis on training and change management in order to prepare Grid Operators to fully utilize the capabilities of the ADMS. The ADMS is one of the foundational tools for the Grid Operators, transitioning from operating system–level devices toward understanding more complex and more abundant paths of electricity flow at the distribution level. Therefore, the Companies will be requesting recovery of these training costs via the EPRM mechanism until such costs are reflected in base rates established in the

Companies' respective rate cases or other rate making proceeding. The training costs incurred during the implementation of the project are included in Figures 15 and 16.

Additionally, in preparation for the Project and prior to Commission approval of the Project, the Companies contracted the services of a third-party change management firm to perform a job gap analysis and help identify the training needs. This effort will help the Companies understand the paradigm shift of needed skills and ADMS tasks for Grid Operators, Trainers, and other System Operation staff. The Job Task Analysis and Job Role Impact Analysis will visually display our risk and change factors and gaps. As a result, the Companies can then develop the necessary competence training and curriculum for using the ADMS in the Companies' very near future. Also, Job Positions may be redefined, which necessitates workforce planning. This is an important step in ensuring the Companies are successful in their implementation and are set up and organized to utilize the software's capabilities as intended. The Companies will be requesting to defer these costs and recover them via the EPRM mechanism until such costs are reflected in base rates established in the Companies' respective rate cases or other rate making proceeding.

Company	Estimate ($)
Hawaiian Electric	[redacted]
Hawai'i Electric Light	[redacted]
Maui Electric	[redacted]
Total	[redacted]

Figure 17 – Implementation Cost for Pre-Implementation Job Analysis

2. Field Devices

The combined Capital and Expense Costs for the Field Device component of the GMS over its anticipated over a five-year implementation period is are estimated at $54.7 million. The capital cost estimate aligns with the original GMS conceptual budget estimate for Field Devices that provide sensing and measurement, distribution automation, and volt-VAR management as identified in the August 2017 GMS.[37] As part of this application, the Companies will be requesting recovery of both Capital and Expense costs via the EPRM mechanism until such costs are reflected in base rates established in the Companies' respective rate cases or other rate making proceeding.

The implementation costs for the Field Devices are broken down by utility and accounting treatment, as shown in Figure 18.

[37] See GMS at 110, Table 9.

Company	Account Group	Year 1	Year 2	Year 3	Year 4	Year 5	Subtotal
Hawaiian Electric	Capital	$3,048,760	$5,710,101	$7,975,673	$9,387,660	$7,688,273	**$33,810,467**
Hawaiian Electric	Operations & Maintenance	$49,399	$79,670	$121,844	$174,382	$221,661	**$646,956**
Subtotal		**$3,098,159**	**$5,789,771**	**$8,097,517**	**$9,562,042**	**$7,909,934**	**$34,457,423**
Hawai‘i Electric Light	Capital	$860,624	$1,022,194	$1,534,411	$1,959,539	$1,512,448	**$6,889,216**
Hawai‘i Electric Light	Operations & Maintenance	$14,167	$21,669	$35,974	$50,454	$72,529	**$194,793**
Subtotal		**$874,791**	**$1,043,863**	**$1,570,385**	**$2,009,993**	**$1,584,977**	**$7,084,009**
Maui Electric	Capital	$1,393,332	$1,931,555	$3,130,554	$3,612,893	$2,935,344	**$13,003,678**
Maui Electric	Operations & Maintenance	$3,153	$12,557	$29,579	$50,769	$69,353	**$165,411**
Subtotal		**$1,396,485**	**$1,944,112**	**$3,160,133**	**$3,663,662**	**$3,004,697**	**$13,169,089**

Figure 18 – Implementation Cost by Company and by Year

The Capital costs are generally broken down into the following six cost categories: (1) internal labor, (2) materials, (3) outside services, (4) overheads, and (5) allowance for funds used during construction ("AFUDC") and are displayed in Exhibit G (*Updated GMS Phase 2 Project Costs*).

The internal labor cost category, which totals approximately [redacted] includes costs for existing company resources required to support the project's deployment. These labor costs would be capitalized. Details of internal labor costs by utility are provided in Exhibit G (*Updated GMS Phase 2 Project Costs*).

The material cost category, which totals approximately $20.8 million, includes the cost for the Field Devices and supporting communications equipment. Details of the material costs by utility are provided in Exhibit G (*Updated GMS Phase 2 Project Costs*).

The outside services cost category, which totals approximately $1.1 million, includes costs for consultants to support the management of the program. Details of the outside services costs by utility are provided in Exhibit G (*Updated GMS Phase 2 Project Costs*).

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 of 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 $2.8 million.

B. ONGOING OPERATIONS AND MAINTENANCE COSTS[38]

1. ADMS

As components of the ADMS system are deployed and modules are put into production, the Companies will also incur new, incremental, ongoing O&M expenses. The major O&M expense items include Internal Labor (incremental staff requirements for operations and technical support), Vendor Support (annual software licensing, support, and maintenance), and Technical Environment (incremental telecom costs and software/hardware maintenance). The Companies will be requesting to defer and recover these expenses through the EPRM Mechanism, as described in Exhibit C (*Accounting and Ratemaking Treatment*). This will be offset by [redacted] due to the retirement of the existing OMS at Hawaiian Electric and [redacted] for existing data historian software maintenance fees under a non-Enterprise Agreement.

Internal Labor and system maintenance costs are expected to ramp up to approximately $2.6 million per year over the course of the project implementation as the solution is put into production across the islands, as shown in Figure 19. This includes approximately [redacted] million for new additional staffing. The exact staffing and enterprise IT cost per Company will depend on the final implementation. However, the Companies will endeavor to reduce the need for additional headcount once we have partially implemented the ADMS with the ADMS vendor because it will provide us with a better idea of the scope of the project and the resources required to operate and maintain the system.

Vendor Support costs are expected to ramp up to [redacted] per year over the course of the project implementation as software modules are put into production.

The incremental telecom costs are expected to be [redacted] per year to reserve inter-island bandwidth between control rooms, application servers, and SCADA front-end communication nodes.

Company	Description	Year 1	Year 2	Year 3	Year 4	Year 5	Beyond Year 5
Hawaiian Electric	Vendor Support		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawaiian Electric	Telecom Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[38] The GMS conceptual budget did not include O&M costs. See GMS at 110, Table 9.

Hawaiian Electric	Labor and Labor Related Expense						[redacted]
Hawai'i Electric Light	Vendor Support		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawai'i Electric Light	Telecom Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawai'i Electric Light	Labor and Labor Related Expense						[redacted]
Maui Electric	Vendor Support		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Maui Electric	Telecom Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Maui Electric	Labor and Labor Related Expense						[redacted]
	Total Annual O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$2,602,289

Figure 19 Annual Operations and Maintenance Expense Continued after Project Implementation

2. Field Devices

As the Field Devices are deployed and are put into production, the Companies will also incur new, incremental, ongoing operations and maintenance ("O&M") expenses, shown in Figure 20. The major O&M expense items include Vendor Support (annual software licensing, support, and maintenance) and Materials (incremental cost for battery replacements). The Companies will be requesting to defer and recover these expenses through the EPRM Mechanism, as described in Exhibit C (*Accounting and Ratemaking Treatment*).

Over the five-year implementation period, vendor support costs are expected to ramp up to $264,838 per year and material costs are expected to ramp up to $49,920 per year.

Company	Description	Year 1	Year 2	Year 3	Year 4	Year 5	Beyond Year 5
Hawaiian Electric	Operations & Maintenance	$49,399	$79,670	$121,844	$174,382	$221,661	$226,094
Hawai'i Electric Light	Operations & Maintenance	$14,167	$21,669	$35,974	$50,454	$72,529	$73,980
Maui Electric	Operations & Maintenance	$3,153	$12,557	$29,579	$50,769	$69,353	$70,740
	Total Annual O&M	**$66,719**	**$113,896**	**$187,397**	**$275,605**	**$363,543**	**$370,814**

Figure 20 Annual Operations and Maintenance Expense

VI. BILL IMPACT

As shown in Exhibit H (*Updated Bill Impact*), the Companies estimate that the average monthly bill impact of the ADMS Project for a typical residential customer would be:

- $0.21 at Hawaiian Electric for a customer using 500 kWh, ranging from $0.11 to $0.28;
- $0.82 at Hawai‘i Electric Light for a customer using 500 kWh, ranging from $0.45 to $1.05; and
- $0.76 at Maui Electric for a customer using 500 kWh, ranging from $0.41 to $0.99.

As shown in Exhibit H (*Updated Bill Impact*), the Companies estimate that the average monthly bill impact of the Field Devices Project for a typical residential customer would be:

- $0.14 at Hawaiian Electric for a customer using 500 kWh, ranging from $0.04 to $0.32;
- $0.21 at Hawai‘i Electric Light for a customer using 500 kWh, ranging from $0.08 to $0.51; and
- $0.32 at Maui Electric for a customer using 500 kWh, ranging from $0.09 to $0.79.

VII. 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 Hawai‘i's RPS goals. Beginning with the GMS Phase 1 Project, the platform developed and deployed as part of the GMS will transition the existing grid to interconnect more renewable integration, enable more customer energy options, and enable exploration of alternatives to meet the needs and expectations of Hawai‘i'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 2 of the Companies' GMS is an integral next step in the Companies' pursuit of the GMS guiding principles of maintaining and enhancing the safety, interoperability, security, reliability, and resiliency of the electric grid, at fair and reasonable costs, while at the same time ensuring optimized utilization of resources and electricity grid assets to minimize total system costs for the benefit of all customers. Phase 2 of the GMS consists the implementation of:

1. An ADMS implemented through three releases and modular functionality; (a) an OMS used to manage and track outages; (b) a DMS that monitors and controls switching at the distribution level, including distribution SCADA, in conjunction with DA; and (c) ADMS "Advanced Applications" — analytic functions for forecasting, simulating, studying, and optimizing the impacts of different network switching configurations and loading conditions., and

2. Distribution automation Field Devices that will integrated with the ADMS to provide monitoring, control and automation capabilities.

The benefits of an ADMS solution in the Hawaiian Electric Companies' grid control rooms and the implementation of Field Devices is to provide greater visibility, control, and optimization of the distribution system for more reliable operations of a two-way grid with increased variable renewable and DER. Additionally, the solution will improve resilience by allowing operators to quickly adapt to changing grid conditions and rapidly recover following power outages and disruptions by enhancing situational awareness and assisting in restoration triage to recover from events faster. The existing outage management processes will also be modernized to leverage ADMS reporting and automation features that improve customer communications, incident response, and operational efficiency.

The total estimated cost of the Phase 2 Project is approximately $104.8 million, which will result in modest average bill impacts of $0.24, $0.76 and $0.72 for typical residential customers at Hawaiian Electric, Maui Electric and Hawai‘i Electric Light, respectively. Although it is impracticable to aggregate GMS implementation benefits for use in a traditional cost-benefit analysis, Phase 2 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' PSIP.

By employing a targeted approach to carrying out Phase 2 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

Grid Modernization Strategy Phase 2 ADMS and Field Device Application

Accounting and Ratemaking Treatment

ACCOUNTING & RATEMAKING TREATMENT[1]

The Hawaiian Electric Companies[2] propose the following accounting and ratemaking treatment specific to the accompanying application for the Advanced Distribution Management System ("ADMS") and Field Device components, herein referred to as the Project ("Project"), of the second phase ("Phase 2") of their Grid Modernization Strategy[3] implementation.

The ADMS is a software project consisting of computer hardware and the associated cost of installing the equipment, software, software development, software services, training, and significant interconnection and integration to enable the full benefits of this project and future programs. The Field Devices project includes the design, procurement, and installation of distribution automation devices, including Secondary VAR Controllers ("SVCs"), line sensors, remote fault indicators ("RFIs"), and remote intelligent switches (reclosers, smart fuses).

The proposed accounting for the ADMS's and Field Devices' 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 their related software and development costs for the project will be deferred. 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 2 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,"[4] of the Financial Accounting Standards Board ("FASB").

The proposed accounting for the ADMS and Field Devices is described below.

I. ADVANCED DISTRIBUTION MANAGEMENT SYSTEM AND FIELD DEVICES

The cost of the ADMS consists of capital, deferred, and expense costs, and the cost of Field Devices consists of capital and expense costs, each of which are described further below.

The Company will follow its existing general policies and procedures with respect to accounting for the ADMS and Field Devices project costs.

A. CAPITAL COSTS

Project costs will be capitalized following the Company's existing practices for capital costs. Costs will be included in construction work in progress and transferred to plant in service

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[1] Note: References to exhibits in this document refer to exhibits included in the accompanying application unless otherwise noted.
[2] Hawaiian Electric, Hawai‘i Electric Light and Maui Electric are collectively referred to as the "Hawaiian Electric Companies" or the "Companies."
[3] See "Modernizing Hawaii's Grid For Our Customers," filed in Docket No. 2017-0226 on August 29, 2017 ("GMS," "Grid Modernization Strategy," or "Strategy").
[4] 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.

upon completion. Depreciation/amortization will commence starting the beginning of the calendar year following the date the equipment or device is placed in service. Specific treatment will be as follows:

The capital costs for the ADMS include the computer hardware (servers) and any related installation expenses. As noted in Exhibit B (*Updated Project Justification with Business Case Support*), the Companies are proceeding with a hybrid approach that decentralizes the critical production operations while centralizing non-production hardware used for purposes such as development and testing. Therefore, hardware will be installed at each of the Companies, and centralized infrastructure that will be shared by the Companies will be installed at Hawaiian Electric.

The Companies will capitalize the ADMS hardware (servers). The new hardware will be included in plant-in-service when received and efforts to install and configure the system commence and the cost amortized over five years, beginning January 1 of the year following the receipt of the hardware. This is consistent with the Companies' latest Commission approved amortization period for computer equipment.

There will be Non-production environment hardware and Production environment hardware:

- Non-production environment hardware will be centralized and physically located on Oahu at Hawaiian Electric facilities. The hardware will benefit customers of all three companies. Therefore, Hawaiian Electric will capitalize the asset and amortize it over five years beginning January 1 following the year the hardware is capitalized. The amortization of computer equipment will be allocated between the Companies with 70% recorded to Hawaiian Electric and 15% billed to each of Hawaii Electric Light and Maui Electric. Rate base plant and accumulated depreciation will be recorded at Hawaiian Electric, where the capital resides.

- Production environment hardware specific to each Company (i.e., decentralized production hardware) will be allocated 100% to the respective Company, capitalized and amortized over five years beginning January 1 following the year the hardware is capitalized.

Hawaiian Electric will house both the centralized non-production hardware and its production hardware for the Oahu grid. As of the date of this application, Hawaiian Electric was unable to obtain the breakdown of cost between the Non-production environment hardware and Production environment hardware. Therefore, the cost for hardware for Hawaiian Electric was split in half. With half allocated for the non-production hardware and half allocated for the production hardware. The actual cost of the Non-production environment hardware will be used when obtained from the vendor.

The Companies will also capitalize the Field Devices that include SVCs, line sensors, RFIs, and remote intelligent switches (reclosers, smart fuses) to enhance grid capabilities and flexibility with the goal of enabling additional distributed and renewable energy resources. The capital costs for the Field Devices include the design, procurement, and installation of the devices. The Field Devices will be transferred to plant-in-service upon successful installation and commission and will be depreciated or amortized beginning January 1 of the year following the installation of the device. SVCs have an average service life of 30 years and depreciation rate of 4.75% and remote intelligent switches have an average service life of 53 and 55 years and corresponding depreciation rate of 2.31% and 2.68%, respectively, depending on whether they are installed as overhead or underground devices. This is consistent with the Companies' latest Commission approved average service life and deprecation rates for Distribution Plant – Line Transformers, Overhead Conductors and Devices and Underground Conductors and Devices. Line sensors and RFIs will be amortized over 15 years which is consistent with the Companies' latest Commission approved amortization period for communication equipment.

The capital costs are proposed to be recovered through the EPRM until such costs are reflected in base rates established in the Companies' respective rate cases or other rate making proceeding, as discussed in Exhibit D (*Exceptional Project Recovery*).

B. DEFERRED COSTS

As described in Section II of this exhibit, the Companies propose to account for the ADMS 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 an allowance for funds used during construction ("AFUDC") while the software is under development.

The Companies deferred costs for the implementation of the ADMS include: (1) software purchase and the vendor resources to install and configure the system per the requirements in the ADMS RFP; (2) third-party system integrators (which were not part of the RFP) required due to the complexity of the integration to connect the ADMS with the meter and device head end, energy management, and demand response management system; (3) new, incremental personnel to support the implementation of the Project who will continue to operate and/or maintain the system after go-live; (4) contract labor resources to supplement the workforce in the testing and validation of the new work processes being implemented; and (5) software purchase of an Enterprise License from OSI Soft for the PI system[5]. Carrying cost equivalent to the AFUDC rate would be applied to the deferred costs after the software is in use until the deferred costs are included in rate base in determining rates or recovered via EPRM. These deferred costs will be amortized over 12 years, beginning when such amortization is included in rates or EPRM, and the unamortized deferred costs are included in rate base (see Exhibit D). There are no deferred costs associated with the implementation of the Field Devices.

As noted above, the Companies are proceeding with a hybrid approach that decentralizes the critical production operations while centralizing non-production hardware (servers) used for

[5] For clarification purposes, the ADMS is from Open Systems International, (OSI). OSIsoft is now part of AVEVA and provides the PI System, which is a time-series database that provides secure data collection in a centralized repository and includes digital tools for data extraction, data mining and data visualization. The two companies have similar names but are not the same company.

purposes such as development and testing. Therefore, there will be software development at each of the Companies as well as some development on centralized functionality that will be performed at Hawaiian Electric.

For the centralized software development, the ADMS vendor allocated development costs amongst the three utilities. For the centralized software development from the ADMS vendor that was not allocated by utility and the OSI Soft PI Enterprise license, since the systems will benefit all customers, the Companies will allocate the costs among the three utilities such that 70% of the total consolidated costs will be borne by Hawaiian Electric, 15% by Maui Electric, and 15% by Hawaiʻi Electric Light. Otherwise, software development specific to each Company will be allocated 100% to the respective Company.

Depending on the respective Company, the deferred costs are proposed to be recovered through the EPRM, effective the month after the go-live date to no later than January 1st of the next year's annual MPIR/EPRM filing, until such costs are reflected in base rates established in the Companies' respective rate cases or other rate making proceeding. (see Exhibit D).

C. EXPENSES

The Companies will incur ADMS-related expenses related to pre-implementation, implementation, post-implementation (e.g., customer to transformer mapping for the OMS module of the ADMS, customer end-user training, incremental telecom costs, project closing costs, support, software upgrades, and maintenance related to the ADMS and OSI PI software) and miscellaneous office supplies discussed below. Over the course of the project, to the extent that implementation and post-implementation costs are not recovered in current rates, the Companies request to estimate these costs and recover the current year's incremental O&M expenses through the annual MPIR/EPRM filing effective January 1st and reconcile to actual O&M expense in the subsequent year via the EPRM adjustment mechanism. These costs will be incurred with each ADMS release and have not been included in existing rates[6,7] (see Exhibit D). These costs will also be offset by licensing and maintenance fees from the existing OMS, which will be discontinued once the ADMS is in place, and from existing maintenance fees that Hawaiian Electric pays for its existing time-series database repository, which will be replaced by a maintenance fee for an enterprise license structure to standardize a time-series database repository, resulting in a combined annual savings of $385,573. The Company proposes to include the annual O&M savings related to the existing time-series database respository of [redacted] in the revenue requirement calculation beginning in 2023, since the enterprise license structure would take effect in 2022. The Company also proposes to include the annual O&M savings related to the retirement of the existing OMS of [redacted] in the revenue requirement calculation beginning in 2024, when the deferred software of Release 1 is placed in service.

Additionally, prior to Commission approval, the Companies will expend funds for job analysis and training assessment as part of the change management preparation. These costs are

[6] Docket No. 2018-0368, *Application For Approval Of A General Rate Increase And Revised Rate Schedules And Rules* filed by Hawaiʻi Electric Light Company, Inc.

[7] Docket No. 2019-0085, *Application For Approval Of A General Rate Increase And Revised Rate Schedules And Rules* filed by the Hawaiian Electric Company, Inc.

titled Pre-Implementation costs. The Companies have contracted the services of a third-party change management firm to perform a Job Task Analysis and Job Role Impact Analysis to visually display our risk and change factors and gaps. They will help the Companies understand the paradigm shift of needed skills and ADMS tasks for System Operators, Trainers, and other System Operation staff and the Companies can then develop the necessary changes to existing position descriptions, competence training and curriculum for using the ADMS in the Companies' very near future-state. The Job Task Analysis and Job Role Impact Analysis take time to analyze and thus to fully take advantage of the ADMS and the additional capabilities it will bring for System Operations, work was required to begin prior to the implementation of the project and the work is being done specifically because an ADMS is anticipated to be installed. Therefore, the Companies are requesting to defer these costs and recover the pre-implementation costs through the EPRM adjustment mechanism effective January 1st of the subsequent year, which has been assumed as January 1, 2022 (see Exhibit D).

Similar to the deferred and capital costs, there will be software development at each of the Companies as well as some development on centralized functionality that will be performed at Hawaiian Electric. The Companies expect to utilize outside services for system integration costs, however the exact amount that the Companies will utilize for the centralized functionality versus the decentralized functionality is not known at this time, thus the outside services system integration costs will be divided by four. The Companies will allocate the costs for this one-fourth of the total system integration costs among the three utilities such that 70% will be borne by Hawaiian Electric, 15% by Maui Electric, and 15% by Hawai‘i Electric Light. Additionally, one-fourth of the O&M cost was allocated to Hawaiian Electric only, one-fourth to Hawaii Electric Light only and one-fourth to Maui Electric only.

For the O&M costs related to the ADMS vendor support, the ADMS vendor allocated development costs amongst the three utilities. For the centralized vendor support for the enterprise data warehouse repository license and telecom costs to support the ADMS integration, the Companies will allocate the costs among the three utilities such that 70% of the total consolidated costs will be borne by Hawaiian Electric, 15% by Maui Electric, and 15% by Hawai‘i Electric Light. Otherwise, the O&M costs related to the software development specific to each Company will be allocated 100% to the respective Company.

The Companies will also incur Field Device-related O&M expenses (e.g. Vendor portal fees, annual software & services fees, battery replacements, etc.). These costs may be incurred as soon as the Field Device is placed in-service and thus have not been included in existing rate cases.[8,9] To the extent that these costs are not recovered in current rates, to reduce the administrative burden, the Companies plan to simplify the EPRM filing to once a year and will request the adjustment on actual incremental O&M incurred during the prior year to be included in and align with the annual MPIR/EPRM filing, until such costs are reflected in base rates established in the Companies' respective rate cases or other rate making proceeding (see Exhibit D).

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[8] Docket No. 2018-0368, *Application For Approval Of A General Rate Increase And Revised Rate Schedules And Rules* filed by Hawai‘i Electric Light Company, Inc.

[9] Docket No. 2019-0085, *Application For Approval Of A General Rate Increase And Revised Rate Schedules And Rules* filed by the Hawaiian Electric Company, Inc.

II. EXISTING ACCOUNTING POLICY FOR SOFTWARE PROJECT COSTS

In D&O No. 18365, filed on February 8, 2001, in Docket No. 99-0207 (*Hawai'i 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.

III. USED AND USEFUL CRITERIA

The used and useful criteria for the ADMS and Field Device components of Phase 2 are described below:

A. ADVANCED DISTRIBUTION MANAGEMENT SYSTEM

The ADMS consists of hardware, software and related software configuration and implementation costs. The ADMS stores, analyzes, and manages, and serves as the system of record that will provide greater visibility, control and optimization of the distribution system for more reliable operations of a two-way grid with increasing DER. The software will be deployed over three Releases, with each Release layering additional capabilities and more sophisticated controls while maintaining cyber security.

The new hardware (servers) will be deemed used and useful and placed into service when received and efforts to install and configure the system commence. Upon successful completion of User Acceptance testing, the respective software and installation components for each Release will be deemed used and useful and placed into service.

The OSI Soft Enterprise PI License is a software structure utilized by OSI to provide the Companies flexibility in expanding PI servers and PI software as explained in Exhibit B (*Updated Project Justification with Business Case*). Under the Enterprise PI License new hardware and software will be deployed for the ADMS at no additional cost and the hardware will be placed into service when received and efforts to install the software have been completed. For this project, the service date is assumed to be December 2022.

B. FIELD DEVICES

Field Devices include SVCs, line sensors, RFIs and remote intelligent switches (reclosers, smart fuses). The Companies will deem the Field Devices and associated installation costs as used and useful upon installation and successful completion of commissioning showing the Field Device able to operate as intended, thereby providing value to the Companies and customers.

Exhibit D Update

Grid Modernization Strategy Phase 2 ADMS and Field Devices Application

Exceptional Project Recovery

INTERIM RECOVERY[1]

As part of the second phase ("Phase 2") of their Grid Modernization Strategy ("GMS") implementation, the Hawaiian Electric Companies[2] are requesting interim recovery of costs related to the Advanced Distribution Management System ("ADMS") and Field Devices project components (collectively referred to as the "Project") through the Exceptional Project Recovery Mechanism ("EPRM" or "Mechanism").

In particular, the Companies are requesting recovery of the Capital ("Capital"), Deferred ("Deferred"), and Operations and Maintenance ("O&M") costs ("Costs") through the Project implementation totaling $104.3 million, including [redacted] million of pre-implementation O&M expenses. The Companies are also requesting recovery of an average of $3.0 million annually in post-implementation incremental O&M expenses through the EPRM Mechanism until new rates become effective that provide cost recovery for the Capital Costs, Deferred Costs, and O&M Costs for the Project for each respective company.

Pursuant to Section III.B.1.(f) of the EPRM Guidelines, the projects and costs that may be eligible for recovery through the EPRM 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 EPRM adjustment mechanism to recover Project costs during the Multi-Year Rate Period. The proposed recovery will conform with the EPRM Guidelines approved in Decision and Order No. 37507 in Docket No. 2018-0088, unless excepted as described in this application.

I. BACKGROUND

On December 23, 2020, the Commission issued Decision and Order No. 37507 ("D&O 37507") in Docket No. 2018-0088, pursuant to which the Commission, among other things, terminated the MPIR Guidelines[3] and immediately replaced it with the Exceptional Project Recovery Mechanism ("EPRM") Guidelines.[4]

The EPRM Guidelines are based in large part on the MPIR Guidelines, with "only a few modifications" to reflect, among other things, that O&M expenses and program costs are eligible for EPRM relief in addition to capital costs and permitting the Companies to include the full amount of approved costs in the EPRM for recovery in the first year the project goes into service.[5]

Although the Companies had requested cost recovery under the MPIR Guidelines in the underlying ADMS Phase 2 Application filed on September 30, 2019, by the instant Supplement

[1] Note: References to exhibits in this document refer to exhibits included in the accompanying application unless otherwise noted.
[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] D&O 37507 grandfathered pending applications for MPIR relief submitted by the Companies prior to the issuance of D&O 37507.
[4] *See* D&O 37507 at 89; Appendix A – EPRM Guidelines.
[5] *Id.* at 88; Appendix B – EPRM Guidelines (redline against MPIR Guidelines).

and Update, the Companies now request recovery of Project Costs under the EPRM Guidelines, as provided by D&O 37507.[6]

As discussed herein, the Companies' proposed recovery of this project complies with the EPRM Guidelines. Therefore, the Companies should be allowed to recover the Project Costs through the EPRM.

A. THE PROJECT QUALIFIES FOR EPRM RECOVERY

1. EPRM Recovery of the Project Costs Will Not be Duplicative

Section II.B.3 of the EPRM Guidelines prohibits duplicative cost recovery and states as follows:

> Notwithstanding any other specific provisions in these Guidelines, the EPRM adjustment mechanism shall not collect or recover revenues for costs or expenses recovered through other effective tariffs or revenue recovery mechanisms, including but not limited to revenues collected through the ARA, PIMs, or SSMs. The utility shall have the burden of proof in an application for recovery of revenues through the EPRM adjustment mechanism that recovered revenues should not be duplicative.[7]

The Companies' Application does not seek duplicative cost recovery. The Project's costs are incremental costs that were not embedded in the rates approved for the Maui Electric 2018, Hawai'i Electric Light 2019, or Hawaiian Electric 2017 or 2020 test year rate cases, nor recovered through any recovery mechanism that is currently in effect.

2. The Project is an Eligible EPRM Project

Pursuant to Section III.B.1 of the EPRM Guidelines, projects and costs that may be eligible for recovery through the EPRM Mechanism are Eligible Projects, including but not restricted to the following illustrative examples, subject to the Commission's approval in accordance with the EPRM Guidelines:

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

[6] D&O 37507 at Ordering Paragraph 5 (If the Companies wish for a pending MPIR application to be reviewed under the EPRM Guidelines, they must make an affirmative written request in the appropriate docket).
[7] Id., Section II at 2.

equipment. Building infrastructure to these projects will encourage additional renewable generation on the grid;

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

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

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

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

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

(g) Service Contracts. Company contracts with third-parties that (1) provide facilities or functionality that could otherwise be provided by a utility capital project and (2)

> provide services that directly and predominantly support another express EPRM Eligible Projects category.

The Project qualifies under Sections III.B.1(b), III.B.1(c), III.B.1(d), and III.B.1(f) of the EPRM Guidelines.

In particular, the Project is an investment in an ADMS and associated Field Devices. The ADMS and Field Devices will build upon the foundational capabilities provided by GMS Phase 1 ("Phase 1"), and will enable enhanced grid control, visibility, and data aggregation functionalities. Like Phase 1, the ADMS and Field Devices are a part of the modern grid platform that will support recent Commission decisions and planning initiatives, such as the approved Distributed Energy Resource ("DER"), Demand Response ("DR") programs, the Community Based Renewable Energy ("CBRE") programs, the Green Infrastructure Loan program, the order for the Companies to submit Electrification of Transportation ("EoT") workplans,[8] as well as the GMS, the Companies' Power Supply Improvement Plan ("PSIP"), and the acceptance of the Companies' Integrated Grid Planning ("IGP") workplans.[9] The Project is therefore eligible under Sections III.B.1.(d) and (f).

In addition, as discussed in Exhibit B (*Updated Project Justification with Business Case Support*), the proposed Project will provide greater visibility, control, and optimization of the distribution system for more reliable operations of a bi-directional power flow grid as an increasing amount of distributed energy resources ("DER") are able to be interconnected to the grid.

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. Combined 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 customer energy options, as reflected by the renewable generation level projections in the *PSIP Update Report: December 2016* and summarized in the Table 1 below.[10]

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

The Project will provide the software system for operators, planners, and other systems to make the most of the data provided by distribution investments, including the advanced meters in Phase 1 and Field Devices. It will ultimately enable additional distributed renewable energy and allow for more advanced, coordinated, and safe management of the grid as the Companies continue to provide customer energy options.

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[8] See D&O 36448
[9] See D&O 36218
[10] See GMS at 3.

Stated differently, as discussed in Exhibit B (*Updated Project Justification with Business Case Support*), the proposed Project will make it possible to operate the grid as more renewable energy is accepted onto the grid through expanded customer participation in DER, DR, and TOU programs. Therefore, the Project also qualifies under Sections III.B.(b) and (c) of the EPRM Guidelines.

3. **The Project Application Complies with Section III.C.3. of the EPRM Guidelines**

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

a. ***Burden of Proof***

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

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

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*[11]. The purpose of the Project is to build upon the capabilities laid out in Phase 1 by implementing an ADMS and deploying Field Devices. The ADMS and Field Devices are key components of a modern grid platform (i.e., the grid the Companies need) that will provide value to customers and will continue to bring additional value when paired with Phase 1 investments as well as subsequent phases. The Project 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 EPRM Guidelines provides:

> Application for recovery of revenues through the EPRM adjustment mechanism shall be made in conjunction with and as part of an application (1) pursuant to General Order No. 7, (2) for deferred accounting treatment, or (3) for other specific project or program authorization or approval. Absent a requirement to file an application for such project or program authorization or approval,

[11] See GMS at 3

> the utility may file a separate independent application for recovery of costs through the EPRM adjustment mechanism.

The Companies' application for recovery of revenues through the EPRM adjustment mechanism is submitted in conjunction with and as part of the accompanying Application, which seeks General Order No. 7 ("G.O.7") approval, deferred accounting treatment, and Project authorization and approval.

c. ***Costs Net of Benefits***

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

> Costs recovered through the EPRM 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' proposed ADMS and Field Device investments are foundational in nature, required to give operators the systems and tools to monitor, control and automate the evolving distribution grid with increasing amounts of customer-owned renewable and distributed resources. The catalyst for these investments is to enable stable grid operations while increasing both centralized and distributed clean and renewable (but also variable) resources in pursuit of Hawai‘i's RPS. The distribution automation Field Devices provide additional sensing and measurement capabilities that provide the grid operators with more situational awareness to proactively manage the gird and improve the quality of electric service for the customers.

The Benefits of implementing an ADMS and the Field Devices can be summarized in three broad categories as discussed in Exhibit B *(Updated Project Justification and Business Case Support).*

1) Enable Customer Energy Options while Advancing Clean Energy Goals

2) Improve System Reliability, Visibility and Customer Communications

3) Enhance Operational Resiliency, Control, and Efficiency

In addition, licensing and maintenance fees from the existing OMS will be discontinued once the ADMS is in place, and existing maintenance fees that Hawaiian Electric pays for an existing data historian/repository will be replaced by a maintenance fee for a standardized time-series database repository for Hawaiian Electric, Hawaii Electric Light and Maui Electric, resulting in a combined annual savings of $385,573. The Company proposes to include the annual O&M savings related to the existing time-series database repository of [redacted] in the revenue requirement calculation beginning in 2023, since the enterprise license structure to standardize a time=-series database repository would take effect in 2022. The Company also proposes to include the annual O&M savings related to the retirement of the existing OMS of [redacted] in the revenue requirement calculation beginning in 2024, when the deferred software of Release 1 is placed in service.

Nevertheless, building upon Phase 1, the ADMS and Field Devices intend to enable and assist in realizing the benefits of customer energy options, including customer participation in DR, DER, and TOU programs. Therefore, the Project costs will be offset by the benefits for customers as identified in Exhibit B (*Updated Device Project Justification with Business Case Support*).

d. ***EPRM Eligibility***

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

> Application for Eligible Projects hereunder shall be made, pursuant to General Order No. 7 procedures, or other applicable authority or procedure. Applications shall explain each basis for claimed EPRM eligibility, indicating the linkage of the project to any previously submitted planning studies, previously submitted construction budgets and any relevant active Commission dockets. Applications shall also include the information set forth in the following paragraphs (e) through (i).

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

e. ***Project Business Case***

Section III.C.3.e. of the EPRM 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 (*Updated Project Justification with Business Case Support*). Additional discussion of the planned execution of investments for Grid Modernization is discussed in Exhibit A (*Grid Modernization Strategy Working Plan*).

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

Section III.C.3.f. of the EPRM 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 Exhibit C (*Accounting and Ratemaking Treatment*), and the *Schedule/Operational Impacts* and *Bill Impact* sections in Exhibit B (*Updated Project Justification with Business Case Support*).

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

Section III.C.3.g. of the EPRM 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 and useful status of the Project's various components are further discussed in Exhibit C (*Accounting and Ratemaking Treatment*).

ADMS

Servers

The Companies will capitalize the hardware (servers) and operating software related to the ADMS upon installation. The servers and operating software are considered turn-key and will be used and useful as soon as they are powered up.

Application Software

The ADMS will be implemented over three releases, each adding additional capabilities and functionality. As each release is completed, or as certain functionalities are made available, the Companies will deem the application software, configuration, and implementation of those ADMS components used and useful upon successful completion of User Acceptance Testing.

Field Devices

The Field Devices will be deemed used and useful once they are installed and commissioned.

h. Costs Net of Savings

Section III.C.3.h. of the EPRM Guidelines provides:

> 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 EPRM 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 A.3.c (Costs Net of Benefits) above, for a discussion of the anticipated costs, net of benefits.

i. Complex Project Treatment

Section III.C.3.i of the EPRM Guidelines provides:

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

As discussed in the Companies' Application and Exhibits, the Project is complex and will affect numerous aspects of the Companies' operations. As noted above, the Project is supported by the detailed business case analysis and documentation set forth in Exhibit B (*Updated Project Justification with Business Case Support*).

j. Procedural Steps

Section III.C.3.j. of the EPRM Guidelines provides:

> Parties to the proceedings on the applications for recovery of costs through the EPRM adjustment mechanism shall endeavor to complete procedural steps to allow for approval of the application within seven months of the date of the application. The Companies acknowledge that the procedural schedule for EPRM for complex

projects may take longer than projects that do not affect numerous aspects of the utility's operations, expenses, or earnings.

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 EPRM for complex projects may take longer than projects that do not affect numerous aspects of the utilities' operations. In particular, as shown in Exhibit B (*Updated Project Justification with Business Case Support*), the Companies anticipate implementation will begin in 2022, which assumes a 9-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. DURATION OF EPRM MECHANISM FOR GMS PROJECT

1. Pre-implementation

The Companies have contracted the services of a third-party change management firm to perform a Job Task Analysis and Job Role Impact Analysis to visually display our risk and change factors and gaps. This will prepare the Companies for the upcoming ADMS system and provide support for change management. They will help the Companies understand the paradigm shift of needed skills and ADMS tasks for System Operators, Trainers, and other System Operation staff. As a result, the Companies can then develop the necessary competence training and curriculum for using the ADMS in the Companies' very near future-state. Also, Job Positions may be re-defined and so workforce planning is necessary. The Companies are requesting to defer these costs and recover the pre-implementation costs through the EPRM adjustment mechanism effective January 1st of the subsequent year, which has been assumed as January 1, 2022.

Company	2021 Estimate ($)
Hawaiian Electric	[redacted]
Hawai'i Electric Light	[redacted]
Maui Electric	[redacted]
Total	[redacted]

Table 2

2. Implementation

For the Project, the Companies request recovery of Capital, Deferred, and O&M Costs through the EPRM Mechanism, totaling [redacted] million for the Project's implementation. These costs are planned to be placed into service at various points during the Project's 2022-2026 implementation period. Table 3 depicts the proposed timing of the ADMS Capital and Deferred of the year they are placed into service or go-live, and annual O&M in the year incurred. Table 4 shows the costs per Release. Table 5 shows the proposed timing of the Field Devices Capital in the year placed into service and annual O&M in the year incurred.

The Companies are requesting EPRM recovery for the capital, deferred and O&M costs incurred during implementation.

The ADMS capital and deferred costs are proposed to be recovered through the EPRM, effective the month after in-service or go-live date, until such costs are reflected in base rates established in the Companies' respective rate cases or other rate making proceeding. As approved in D&O 37507, the EPRM recovery will include the return on the net of tax average annual undepreciated investment or unamortized balance of the deferred cost, except in the initial year the project elements are in service, the investment or deferred cost balance will be calculated as the average of the balance at the in-service date and the balance at the end of the initial year.[12]

The ADMS shared hardware related to centralized non-production hardware (servers) are anticipated to go into service in March 2022. Although the assets will physically be located on Oahu at Hawaiian Electric facilities, the servers will benefit customers of all three companies; therefore the amortization expense, representing the return of the cost of the servers, will be allocated to Hawaiian Electric, Hawaii Electric Light and Maui Electric using rates of 70%, 15% and 15%, respectively. The Companies will seek to recover their share of these costs through the EPRM and will cease recovery through the EPRM until such costs are reflected in base rates established in the Companies' respective rate cases or other rate making proceeding.

Over the course of the project, to the extent that ADMS implementation and post-implementation costs are not recovered in current rates, the Companies request to estimate these costs and recover the current year's incremental O&M expenses through the annual MPIR/EPRM filing effective January 1st and reconcile to actual O&M expense in the subsequent year via the EPRM adjustment mechanism.

According to the EPRM Guidelines, "Accrual of revenues recovered through the EPRM adjustment mechanism for an Eligible Project shall commence upon certification of the project's completion and/or in-service date in accordance with terms approved by the Commission at the time cost recovery through the EPRM adjustment mechanism is approved in the underlying proceeding for EPRM relief."[13] However, since the Companies plan to install the Field Devices over the course of the year, they propose to include in target revenues the EPRM recovery of the Field Devices through their annual MPIR/EPRM filing, to be effective January 1 of the year following the year of installation. The Field Devices of GMS Phase 2 will have certain capital elements going into service and incremental O&M throughout the year. The Companies plan to request an adjustment to EPRM recovery amount based on actual capital costs for assets placed into service and O&M incurred during the prior year.

[12] D&O 37507, Appendix A at 6-7.
[13] D&O 37507, Appendix A at 12.

Company	Account Group	Year 1	Year 2	Year 3	Year 4	Year 5	Subtotal
Hawaiian Electric	Capital	[redacted]					[redacted]
Hawaiian Electric	Deferred		[redacted]	[redacted]		[redacted]	[redacted]
Hawaiian Electric	Operations & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawai‘i Electric Light	Capital	[redacted]					[redacted]
Hawai‘i Electric Light	Deferred			[redacted]	[redacted]	[redacted]	[redacted]
Hawai‘i Electric Light	Operations & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Maui Electric	Capital	[redacted]					[redacted]
Maui Electric	Deferred			[redacted]	[redacted]	[redacted]	[redacted]
Maui Electric	Operations & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 3 ADMS Costs by Capital, Deferred and O&M

Project	Company	Year 1	Year 2	Year 3	Year 4	Year 5	Subtotal
Release 1	Hawaiian Electric	[redacted]	[redacted]				[redacted]
Release 1	Hawai‘i Electric Light	[redacted]		[redacted]			[redacted]
Release 1	Maui Electric	[redacted]		[redacted]			[redacted]
Subtotal		[redacted]	[redacted]	[redacted]			[redacted]
Release 2	Hawaiian Electric			[redacted]			[redacted]
Release 2	Hawai‘i Electric Light				[redacted]		[redacted]
Release 2	Maui Electric				[redacted]		[redacted]
Subtotal				[redacted]	[redacted]		[redacted]

Release 3	Hawaiian Electric					[redacted]	[redacted]
Release 3	Hawai'i Electric Light					[redacted]	[redacted]
Release 3	Maui Electric					[redacted]	[redacted]
Subtotal						[redacted]	[redacted]

Table 4 ADMS Capital and Deferred Costs by Release

Company	Account Group	Year 1	Year 2	Year 3	Year 4	Year 5	Subtotal
Hawaiian Electric	Capital	$3,048,760	$5,710,101	$7,975,673	$9,387,660	$7,688,273	**$33,810,467**
Hawaiian Electric	Operations & Maintenance	$49,399	$79,670	$121,844	$174,382	$221,661	**$646,956**
Subtotal		**$3,098,159**	**$5,789,771**	**$8,097,517**	**$9,562,042**	**$7,909,934**	**$34,457,423**
Hawai'i Electric Light	Capital	$860,624	$1,022,194	$1,534,411	$1,959,539	$1,512,448	**$6,889,216**
Hawai'i Electric Light	Operations & Maintenance	$14,167	$21,669	$35,974	$50,454	$72,529	**$194,793**
Subtotal		**$874,791**	**$1,043,863**	**$1,570,385**	**$2,009,993**	**$1,584,977**	**$7,084,009**
Maui Electric	Capital	$1,393,332	$1,931,555	$3,130,554	$3,612,893	$2,935,344	**$13,003,678**
Maui Electric	Operations & Maintenance	$3,153	$12,557	$29,579	$50,769	$69,353	**$165,411**
Subtotal		**$1,396,485**	**$1,944,112**	**$3,160,133**	**$3,663,662**	**$3,004,697**	**$13,169,089**

Table 5 Field Device costs by Capital and O&M

3. Annual Operations and Maintenance

Table 6 shows the ADMS estimated annual incremental implementation and post-implementation O&M costs for each Company and Table 7 shows the Field Devices estimated annual incremental O&M costs for each Company, of which both are expected to ramp up to approximately $3.0 million per year over the course of the project implementation as the solution is put into production across the islands. However, the Companies will endeavor to reduce the need for additional headcount once they have partially implemented the ADMS with the ADMS vendor because it will provide us with a better idea of the scope of the project and the resources required to operate and maintain the system. The incremental Labor and Labor Related Expenses include labor that is currently not in base rates, which will be used to maintain and operate the ADMS.

Company	Description	Year 1	Year 2	Year 3	Year 4	Year 5	Beyond Year 5
Hawaiian Electric	Vendor Support		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawaiian Electric	Telecom Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawaiian Electric	Labor and Labor Related Expense						[redacted]
Hawai'i Electric Light	Vendor Support		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawai'i Electric Light	Telecom Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawai'i Electric Light	Labor and Labor Related Expense						[redacted]
Maui Electric	Vendor Support		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Maui Electric	Telecom Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Maui Electric	Labor and Labor Related Expense						[redacted]
	Total Annual O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 6 Annual O&M Expenses Continued after Project Implementation

Table 7 shows the Field Device estimated annual incremental O&M costs for each Company, which is expected to ramp up to approximately $0.4 million per year over the course of the project implementation and post-implementation as more Field Devices are placed into service across the islands.

Company	Description	Year 1	Year 2	Year 3	Year 4	Year 5	Beyond Year 5
Hawaiian Electric	Operations & Maintenance	$49,399	$79,670	$121,844	$174,382	$221,661	$221,661
Hawai'i Electric Light	Operations & Maintenance	$14,167	$21,669	$35,974	$50,454	$72,529	$72,529
Maui Electric	Operations & Maintenance	$3,153	$12,557	$29,579	$50,769	$69,353	$69,353
	Total Annual O&M	**$66,719**	**$113,896**	**$187,397**	**$275,605**	**$363,543**	**$363,543**

Table 7

Exhibit H (*Updated 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 that are discussed further in Exhibit H (*Updated Bill Impact*). In the annual EPRM 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 EPRM calculation is provided in Exhibit I (*Hawaiian Electric Companies' Decoupling Calculation Workbook*).

The various revenue requirement components are addressed below:

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

b. Rate of return assumption (EPRM Guidelines Section III.C.2.b.i) – 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 [*Hawaiian Electric Companies' Decoupling Calculation Workbook*]). Cost of Capital will be based on the weights and rates in effect for rates at the time of the EPRM 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) (EPRM Guidelines Sections III.C.2.b.i and III.C.3.c) (See Exhibit I [*Hawaiian Electric Companies' Decoupling Calculation Workbook*]). 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).

Exhibit E

Grid Modernization Strategy Phase 2 ADMS and Field Device Application

Procurement Process

PHASE 2 PROCUREMENT PROCESS

This supplement and update of the Application[1] ("Supplement") for the Advanced Distribution Management System ("ADMS") and field devices ("Field Devices") component of Phase 2 of the implementation of the Grid Modernization Strategy ("GMS"),[2] is herein referred to as the "Project." This Project is part of the initial groundwork to build the platform needed to create the foundation for a modernized grid that is consistent with the Hawai'i Public Utilities Commission's ("Commission") principles for a modern grid.[3] Accordingly, the goal of Phase 2 is to enable advanced distribution monitoring, control, and automation capabilities. To achieve this functionality, the Project Supplement includes an ADMS, which serves as a back-office system that can efficiently monitor, visualize, and control distribution grid conditions. The Project Supplement also include distribution automation Field Devices which will provide operators with situational awareness and the tools needed to take preventative or corrective actions to improve the quality of electric service for customers.

The procurement for the Field Devices will be completed separately from the ADMS. Field Devices are currently being procured under existing contracts. The RFP process described below explains how the Field Devices were procured and how they will be procured in the future.

I. ADMS PROCUREMENT PROCESS

A. REQUEST FOR PROPOSALS

The Advanced Distribution Management System ("ADMS"), serves as a back office system that can efficiently monitor, visualize, and control distribution grid conditions. The ADMS will also include systems integration to connect the ADMS with existing Energy Management Systems ("EMS"), the recently approved Decentralized Energy Management System ("DEMS"), the Companies' Geographic Information System ("GIS"), which tracks the geographic location of components of the distribution grid, and the Phase 1 MDMS.

The Companies followed a best-practice Request for Proposal ("RFP") competitive process to select from the pool of existing commercial off-the-shelf software solutions. This RFP process was conducted by a cross-functional team at the Hawaiian Electric Companies guided by an external consultant with subject matter expertise in the area of ADMS procurement and ADMS implementation.

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[1] The original Application in this proceeding, filed on September 30, 2019, sought approval of the advanced data management system ("ADMS"). This filing supplements that Application by adding Field Devices and updating the original Application.
[2] See Docket No. 2017-0226, *Modernizing Hawai'i's Grid For Our Customers*, filed on August 29, 2017.
[3] See GMS, Section D (Guiding Principles), at 51-52.

B. RFP DEVELOPMENT PROCESS

The ADMS RFP leveraged the significant effort that was invested in the first ADMS RFP, which commenced as part of the Smart Grid Foundation Project ("SGFP") procurement process. The Companies gathered ADMS requirements with the assistance of an external consultant and issued the RFP to various vendors in the industry utilizing the Gartner[4] research of ADMS companies and their market share in the utility market. Eventually the Companies re-evaluated the need and the maturity of the ADMS product and cancelled the first ADMS RFP and it was not included as part of the SGFP Application. The first ADMS RFP process was conducted in 2015.

Following the filing of the GMS, the Companies attended Distributech 2018 in San Antonio, Texas. Distributech is an annual conference held in the continental United States where vendors display and hold sessions about the latest technology for operating and maintaining utility grids and where other utility grid counterparts, including the Companies, present their latest project endeavors. A group of System Operation personnel attended this conference and observed the advancement in functionality of the ADMS products compared to what was available in the 2015 time frame (current products are available off-the-shelf with less customization required), especially in the ability to address distributed energy resources ("DER"). Thus, along with the GMS filing, a team was formed to begin procuring an ADMS.

Taking some lessons learned from the first ADMS RFP process, the Companies, with the assistance of an external consultant, first gathered information about the current state of outage management and distribution network management operation processes and systems and then identified the future state operational needs and Use Cases[5] for an ADMS. The Companies then refined the functional and technical requirements from the first ADMS RFP to align with the GMS vision, which is for the ADMS to serve as a back office system that can efficiently monitor, visualize, and control distribution grid conditions. The Use Cases helped to define what issues the Companies are currently struggling with in light of the increased penetration of DER and variable and renewable generation. The demonstrations by ADMS vendors at Distributech 2018 helped the System Operation personnel to understand the functional capabilities of today's ADMS systems. In addition, the use of an outside consultant allowed the Companies to understand what features and functions other utilities were using with an ADMS. This approach ensures that the requirements being utilized by the Companies are not unique but is the result of collaboration with other utilities and an articulation of industry need to potential suppliers. More importantly, tailoring the ADMS requirements to Hawai‘i via the Use Cases helps to justify why an ADMS is needed and ensures the ADMS will meet the future needs of the Companies' modernized grid. The ADMS requirements covered all of the topics involved with an ADMS as shown and explained in Section II.C of Appendix B *(GMS Phase 2 Project Justification with Business Case Support)*.

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[4] https://www.gartner.com/en/about/
[5] See Attachment A.

C. SUMMARY OF THE RFP PROCESS

The schedule below outlines the overall procurement process after the ADMS RFP was developed. The process began with the issuance of RFP materials to bidders in late 2018, followed by a period allowing bidder questions before proposals were due. Shortly after the proposals were submitted by bidders, the Companies held interviews with the bidders for each RFP to clarify all aspects of the bidder response. From there, the proposals were evaluated against a predetermined evaluation methodology, and the bidders went through different stages of evaluations that included an onsite demonstration and a "best and final offer" solicitation to reach the decision for award selection. During each portion of the procurement process, significant due diligence was done in an effort to minimize risk and ensure that the bidder solution aligns with the Companies' vision and anticipated needs.

The Companies' goal is to complete vetting, testing, and contract negotiations prior to a Commission decision on the Application for the ADMS component of Phase 2 Grid Modernization, meaning that should the Commission issue a favorable decision approving the Application, procurement and implementation can begin immediately.

The bidder's compliance with the specified requirements, comments, and responses to clarification questions were factored into the technical evaluation. Furthermore, the procurement team sought input on bidder solutions and product specifications in an effort to consider Tri-Company as well cross-organization input.

D. SCHEDULE

The RFP process occurred during the first half of 2019 according to the following schedule:

Activity	Start	Completed
Prepare RFP materials	November 1, 2019	December 27, 2018
RFP Issued	December 28, 2018	December 28, 2018
Question and Answer Period	January 6, 2019	February 18, 2019
Define Decision Criteria	January 1, 2019	February 1, 2019
RFP Responses Due		February 22, 2019
Preliminary Vendor Scoring	February 22, 2019	April 1, 2019
Vendor Shortlist Announcement		April 10, 2019
Prepare Demonstration Scripts	March 1, 2019	April 15, 2019
Demonstration Scripts Issued		April 11, 2019
Vendor On-site Demonstrations	May 6, 2019	June 13, 2019
Final Vendor Scoring	June 15, 2019	July 1, 2019
Reference Checks for Down Selected Vendors	June 13, 2019	June 20, 2019
Vendor Selection		July 15, 2019
Vendor Notification		August 1, 2019

E. MATERIALS

The complete RFP materials package is included as Attachment1 to this Exhibit.

F. EVALUATION CRITERIA

The Companies evaluate vendors using a Least Reasonable Cost methodology that balanced solution functionality, usability, and total cost of ownership. A vendor-scoring framework was created with the following relative scoring weights –

- **Pass/Fail –** Overall evaluation of adherence to RFP Instructions, Standard Contract Terms and Conditions, Commercial Risk, and Customer Support
- **45% Functionality** – An assessment of how well the solution fits the Companies' requirements, including system functionality, technical architecture, and related vendor services.
- **30% Usability** – An assessment of solution usability according to a cross-section of systems operators and technical support staff, as determined during onsite vendor demonstrations.
- **25% Total Cost of Ownership** – An assessment of the relative implementation and operating cost of each vendor option over the next 12 years.

These criteria were scored in a series of corresponding evaluation stages.

G. EVALUATION STAGES

Vendor scoring was conducted in a series of stages to gradually reduce the field of candidates.

- **Stage 1 (Pass/Fail)** – Eliminate any vendors that did not meet minimum Mandatory Requirements. Only those vendors that passed were evaluated in Stage 2.
- **Stage 2 (45% of Total Score)** – Evaluate vendor written responses, especially the ability for their proposed solution to meet the required Functionality. Invite a short-list from the highest scoring vendors to participate in Stage 3.
- **Stage 3 (30% of Total Score)** – Conduct onsite vendor demonstrations and reference checks to assess Usability. Select from the highest scoring vendors to participate in Stage 4.
- **Stage 4 (25% of Total Score)** – Calculate the Total Cost of Ownership (over 12 years) for each remaining vendor. Select from the two lowest-cost options. Solicit Best and Final Offers from those vendors and revise the total cost of ownership scores based on their final price proposals.

Stages 1 and 2 required an extensive evaluation of the vendor's response from a cross-functional (Operational Technology, Information Technology, and Procurement) and tri-company evaluation team that read every line of information, especially in Attachment C (Detailed Functional and Technical ADMS Requirements), Attachment D (Technical and Cybersecurity Requirements), and Attachment E (Detailed Cost and Staffing Model). Scores from individual evaluators were then aggregated and averaged based on the evaluation criteria, and vendors were down-selected as they moved through the different evaluation stages. The external consultant reviewed all the proposals as well, but their scores were not incorporated into the evaluation and the consultant was relied upon as a source of technical expertise. Stage 3 required on-site vendor demonstrations, which consisted of three days of vendor demonstrations, in which vendors followed a well-developed script using the Companies' GIS extract information to display their capabilities. Topics outlined in Section II.C of the Business Case (all topics of an ADMS) were covered by the vendor. In most cases the vendor brought a team of about 10–16 people (some by phone and some on-site). The evaluation process required a lot of dedicated time by the System Operation personnel over a period of 8 weeks; however, the ADMS is a critical system for the continued and future incorporation of DER, variable and renewable technology, therefore the time invested into evaluating the ADMS RFP is important. A Final Decision was based on the highest combined Total Score across all Stages.

H. VENDOR SCORING AND DECISIONS

The following table summarizes the actual vendor scoring and decisions at each stage.

Vendor Scoring Summary

[redacted]

Stage	Category	Weight
Stage	Category	Weight
Stage 1	Mandatory Requirements	N/A
	Stage Decision	
	Reject vendors not meeting Mandatory Requirements	
Stage 2	Preferred Vendor Status	—
	Functional Requirements - OMS	10.00%
	Functional Requirements - DMS	10.00%
	Functional Requirements - SCADA	5.00%
	Functional Requirements - Common	5.00%
	Non Functional Requirements	5.00%
	Implementation Services	10.00%
	Stage 2 Score	45.00%
	Stage Decision	
	Shortlist Stage 2	
Stage 3	Bidder Demos	25%
	References	5%
	Product Score Adjustment	0%
	Stage 3 Score	30.00%
	Stage Decision	
	Shortlist Stage 3	
Stage 4	License Price	0.00%
	Implementation Services Price	0.00%
	Support and Maintenance Costs	0.00%
	3rd Party, Hardware and Internal Costs	0.00%
	Total Cost of Ownership over 12 Years	25.00%
	Legal & Contractual Review	100.00%
	Stage 4 Score	25.00%
	Final Decision	
	Total Score	100.00%
	Final Decisio	

[redacted]

I. FINAL DECISION

The selected vendor, Open Systems International ("OSI"), had the highest combined Total Score across all criteria. [redacted] Of the final candidate solution options, the selected vendor provided the best total cost of ownership. The Companies agree the selected vendor is the Least Reasonable Cost solution.

FIELD DEVICE PROCUREMENT PROCESS

II. SUMMARY OF THE RFP PROCESS

The Companies follow a best-practice Request for Quotation ("RFQ") competitive bid process to select the most cost-effective Field Devices. This process required solicitation of at least three (3) competitive bids. The RFQ process is intended to foster broad-based competition among suppliers while ensuring accountability, fiscal responsibility, and efficiency. By following consistent procurement practices, the Company will be able to leverage our buying power, providing safeguards against the misuse of Company funds, and promoting fairness and confidence in supplier selection. Field device procurements are only for a specified time; competition among suppliers is persistent as the procurement will be re-bid on a regular periodic basis.

The schedule below outlines the high-level procurement process. The process began with the issuance of RFQ materials to bidders, followed by a period allowing bidder questions before proposals are due. Shortly after the proposals were submitted by bidders, the Companies may hold interviews with the bidders for each RFQ to clarify all aspects of the bidder response. From there, the proposals will be evaluated against a predetermined evaluation methodology to reach the decision for award selection. During each portion of the procurement process, significant due diligence was done in an effort to minimize risk and ensure that the bidder solution aligns with the Companies' vision and anticipated needs.

A. SCHEDULE

Please see below for the RFQ process that will be followed for the field device procurements.

Activity*	Duration*
Prepare RFQ materials	2 weeks
RFQ Issued	1 day
Define Decision Criteria	1 week
Question and Answer Period	2 weeks
RFQ Development / Submittal	3 weeks
Preliminary Vendor Scoring	1 week
Vendor Selection	1 day
Vendor Notification	1 week

* The activities and durations may differ depending on the complexity of the RFQ.

B. EVALUATION CRITERIA

Prior to the issuance of any bid documents, the evaluation criteria for selecting the winning bid will be documented. The overall goal is to obtain the best value for the Companies by evaluating and comparing all relevant criteria in addition to the cost that best serves the requirements of the Company. The following is a non-exclusive list of factors that may be relevant in evaluating bids:

1. Costs

1. Overall life-cycle cost, including installation, operation, use, and maintenance costs;
2. Near and long-term costs;
3. Necessary costs that may not be included in the bid;
4. Effect on entire system or full build-out of project

2. Product

1. Device capabilities;
2. Alignment with Company requirements.

3. Supplier Considerations

1. Reliability, customer service, and quality;

2. Past performance;

3. Ability, capacity and skill to provide the service required within the time specified;

4. Continuity and compatibility with other jobs/projects;

5. Availability;

6. Long-term viability;

7. Financial State

4. <u>Company Goals</u>

1. Standardization;

2. Compatibility with existing projects and company affiliates;

3. Compliance with laws;

4. Alignment with Grid Modernization Strategy and other Company Goals

C. FINAL DECISION

Generally, the vendor with the highest combined Total Score across all criteria is selected and awarded a contract. However, there may be an exception if it's an emergency procurement or if the material is of proprietary source or exclusive distribution. If a procurement requires an exemption, proper documentation will be required to identify the reason for the exemption and approved by a Vice President. This procurement process allows the Companies to ensure that the selected vendor will provide the best quality at the lowest amount of risk to the Company.

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Exhibit F

Grid Modernization Strategy Phase 2 ADMS and Field Device Application

System Architecture and Cyber Security for Grid Modernization

Table of Contents

I. SYSTEM ARCHITECTURE FOR GRID MODERNIZATION

On August 29, 2017, the Hawaiian Electric Companies[1] submitted their Grid Modernization Strategy ("GMS"),[2] which was 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 the goal of Hawai'i's renewable portfolio standards ("RPS") 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 strategy for the Companies' future, flexible grid platform.

The GMS Phase 1 Platform implementation[5] is focused on providing more granular customer data to empower customers to pursue energy options while also providing more insight into the state of the distribution grid. The combination of advanced meters, field area networks ("FANs"), and meter data management systems ("MDMS") provide a foundational and empowering investment in the capabilities of the grid to meet the collective needs and expectations of customers, stakeholders, the Commission, and the Companies. The Companies have begun to implement the Phase 1 advanced meter proportional deployment per D&O 37655, which approved the updated opt-out proportional approach, and are ready to pursue Phase 2 in a sequential and logical order to build capabilities over time. The GMS Phase 2 ADMS implementation will provide the software system for grid operators and the data for planners and other roles to make manage, analyze, and evolve the distribution grids to meet customer needs. . The GMS Phase 2 Field Device deployment will provide tools for grid operators to monitor and control the distribution grid and provide automation capabilities help to improve distribution voltage management – an important component in improving hosting capacity – while also providing situational awareness, and outage management. The GMS investments will ultimately enable additional distributed renewable energy and allow for more advanced, coordinated, and safe management of the grid as the Companies continue to enable customer energy options.

A. BUILDING A MODERN GRID

As outlined in the main body of the Application, the components of an ADMS—including a Demand Management System ("DMS"), Outage Management System ("OMS"), supervisory control and data acquisition ("SCADA") system, network model, advanced protection, power quality analysis, fault analysis, DER & load forecasting, and power flow

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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*, or Grid Modernization Strategy ("GMS") filed on August 29, 2017.
[3] See Docket No. 2017-0226, Decision and Order No. 35268, issued on February 7, 2018.
[4] See Hawai'i Revised Statutes § 269-92.
[5] See Docket No. 2018-0141, Decision and Order No. 36230, issued on March 25, 2019.

analysis—are core foundational components of a next generation distribution system platform. Figure 1~~Figure 1Figure 1~~ is a re-creation of the U.S. Department of Energy ("DOE") Modern Distribution Grid (DSPx) Report, Volume III,[6] "Figure 8: Next Generation Distribution System Platform & Applications," which was also included in the GMS as Figure 4. This graphic demonstrates how the advanced grid and customer applications are built on top of core components. This foundation provides the basis to enable grid edge and customer applications.

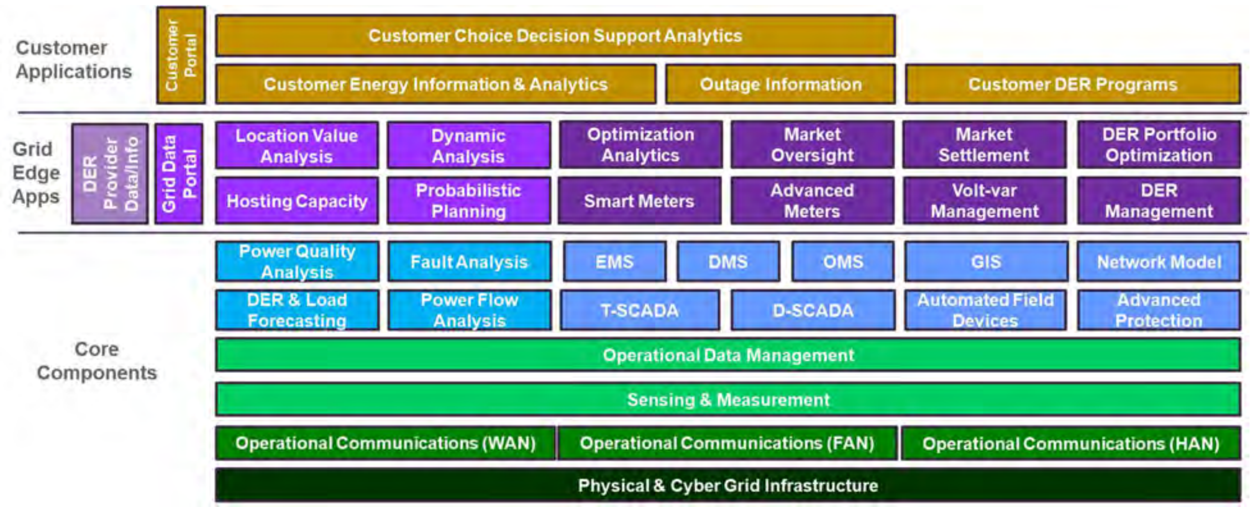

Figure 1

Figure 2 is a re-creation and elaboration of GMS Figure 9, "Current Status of the Companies' Customer-Facing and Advanced Grid Technologies." The color gradient in each of the components illustrates the relative level of Hawaiian Electric Companies' capability in 2017, at the time of the GMS filing.

[6] See U.S. Department of Energy next generation distribution system platform initiative (aka Next-Generation Distribution System Platform (DSPx) Project), Modern Distribution Grid Report, Volume III, available at https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx.

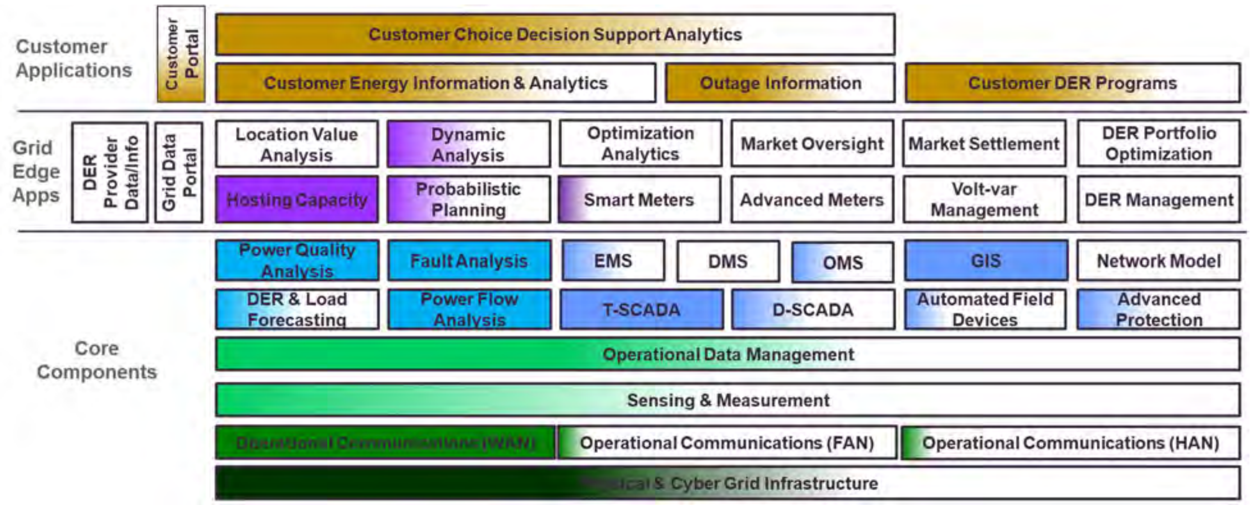

Figure 2

The implementation of GMS Phase 1 and Phase 2 in combination with the capabilities gained through the decentralized energy management system ("DEMS")[7] has systematically gained many of the "Next Generation Distribution System Platform & Applications" identified in the DOE's DSPx initiative. Figure 3 repeats Figure 2, with the addition of color-coded outlines to identify the DSPx components that align with GMS components and the DEMS. Note that the ADMS component of Phase 2 will provide multiple components of the DSPx modern grid platform, but the full value of the ADMS is not unlocked without the accompanying Field Devices (see the "ADMS + Field Devices" blue boxes). Unlike the components outlined in solid colors, the components shown in dashed lines are broader than the Grid Modernization scope of work, but Grid Modernization will partially provide additional capabilities in these areas.

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[7] See Docket Nos. 2015-0411 and 2015-0412. The DEMS is the name of the product that was approved in the DRMS docket. As the Commission recognized with D&O 36476, the line between DR and DER is nuanced from a policy and program perspective. Differentiating between the functions associated with the management software capabilities is similarly nuanced. For the purposes of the Companies' selected architecture, we will be discussing systems in terms of DEMS and ADMS. The industry terms DRMS and DERMS do not comport neatly with the Companies' approach, wherein customer-cited resources will be relied upon for routine grid operation.

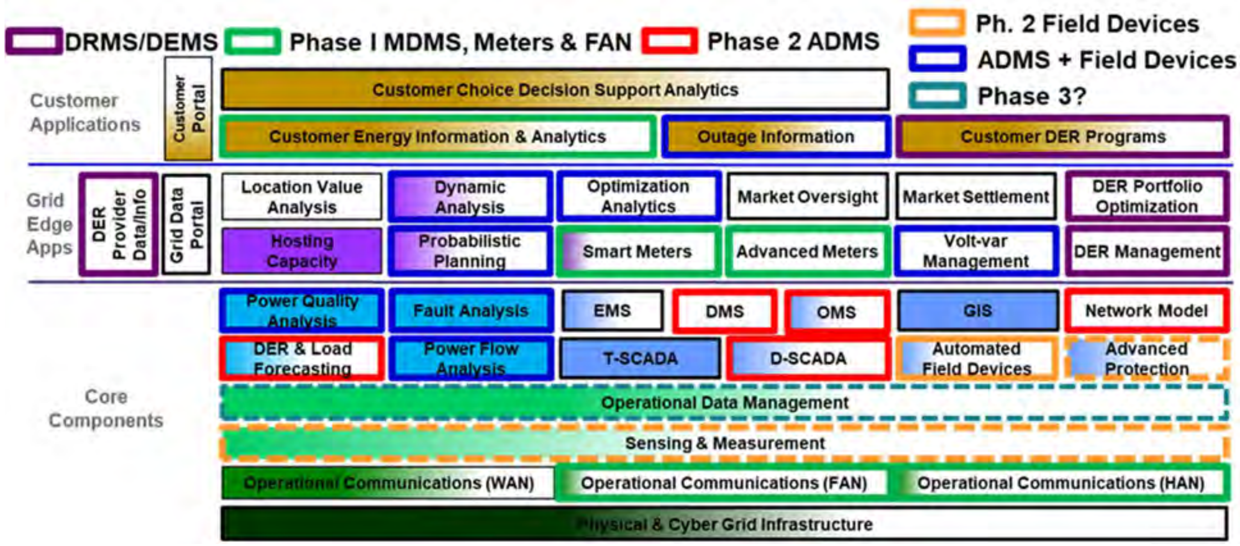
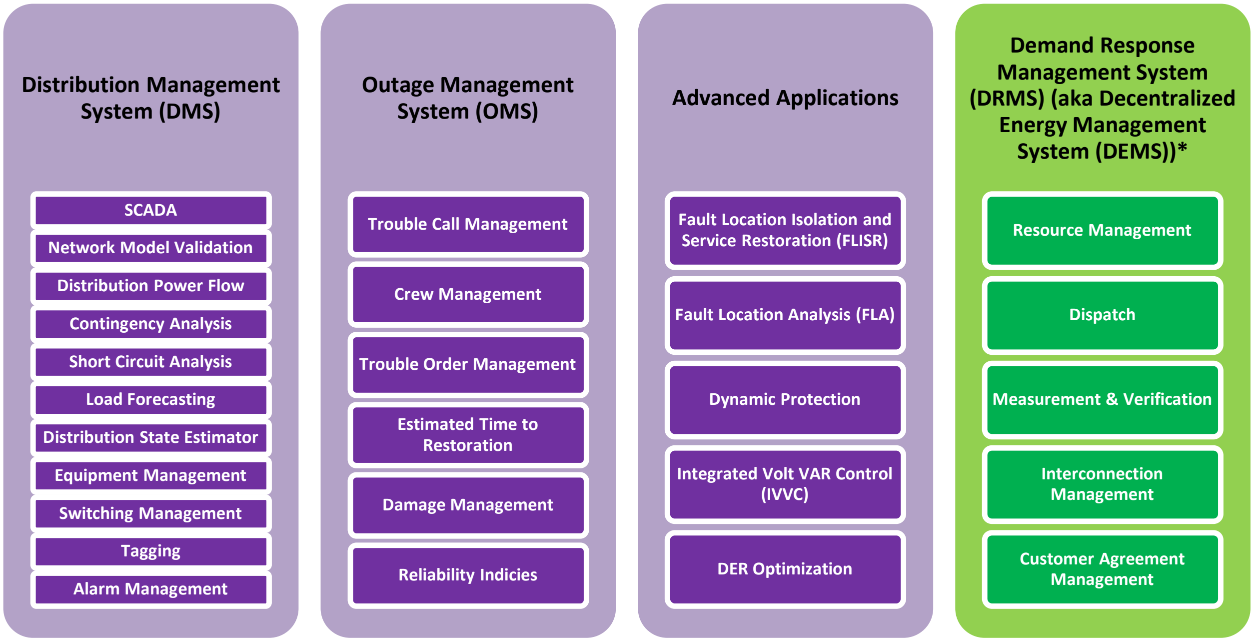


Figure 3

B. COMPONENTS OF AN ADMS

The proposed Phase 2 investment in an ADMS provides the foundational tools that grid operators require to monitor, control, and automate the evolving distribution grid with increasing amounts of variable renewable and distributed resources. Figure 4 illustrates the multiple modules that comprise an ADMS. The catalyst for this investment in an ADMS is to maintain stable grid operations while increasing both centralized and distributed clean and renewable (but also variable) resources in pursuit of Hawai‘i’s RPS while lowering greenhouse gas emissions. A detailed description of each of these ADMS modules is included in Exhibit B (*Updated Project Justification and Business Case Support*).

Industry Reference Components of an Advanced Distribution Management System



*The DEMS was implemented per D&O 36476.

Figure 4

The ADMS will also interact with other operational and corporate systems to provide context to the stream of data coming from Phase 1 meters and Phase 2 Field Devices. For example, the ADMS will integrate with the DEMS system and each Company's existing energy management system ("EMS") to coordinate DER commands and dispatch. As depicted in Figure 5, the ADMS will integrate with the Companies' existing systems, including the following:

- Workforce management systems ("WMS") to facilitate work orders for outage restoration processes and other troubleshooting of field work coordination
- SAP customer information system ("CIS") and geographic information system ("GIS") to provide context about where customers and infrastructure components are located on the distribution grid
- GMS Phase 1 meter head-end, and MDMS to receive and utilize the advanced meter outage notifications and voltage alerts
- GMS Phase 1 telecommunications gateway to receive data from both advanced meters and distribution Field Devices

C. <u>SYSTEMATIC AND LOGICAL IMPLEMENTATION SEQUENCE</u>

The ADMS will provide grid operators with core DMS capabilities. In order for the ADMS to function as needed with the desired capabilities, the GIS data that identifies each component of the distribution grids for each island is loaded into the ADMS with a network model that details how each of the distribution infrastructure components are connected, including switching schemes and phases. The distribution grid has grown over time, with many components dating back to the post–World War II time frame.[8] As a result, paper drawings continue to be digitized, and there will be an effort to continue validation of the distribution model once loaded into the ADMS. The ADMS has some tools to assist with this model validation and will help identify areas that may need a distribution engineering review or field validation to ensure that the infrastructure specifications and connectivity configurations are modeled correctly. This is a common undertaking as utilities work to model the distribution grid in these sophisticated DMS software tools.

The ADMS will also include OMS capability that will receive advanced meter outage alerts as well as outage notifications from other devices such as SCADA and remote fault indicators to coordinate the Companies' outage responses. The Fault Location Isolation and Service Restoration ("FLISR") module of the ADMS helps more accurately identify the location and root cause of an outage. FLISR also recommends switching schemes to minimize the number of customers affected by an outage. Grid operators can then utilize the ADMS to implement the switching scheme with remote intelligent switches. The OMS component of the ADMS then coordinates with field crews to ensure safe and efficient restoration of power by guiding them to the likely source of the outage and tagging the energized and de-energized sections of the system. The OMS also enables outage information updates for customers, including estimated time to restoration, which will continue to be refined as the documented history of outage restoration is accumulated after OMS implementation.

In order to improve field crew efficiency in outage restoration, the OMS component must interface with the SAP WMS, which provides work order details to field crews for system restoration based on the grid operator dispatches, which are guided by insight from the ADMS OMS component. The WMS also receives a work order to perform field validation of infrastructure components, as well as closes the loop on updating the asset management system and GIS when new equipment is installed either during outage restoration or during routine equipment upgrades or aging infrastructure replacement. The updated GIS "as-built" model data then populates the ADMS network model which controls the "as-operated" configuration.

D. INTERFACING WITH THE DEMS

The Commission previously approved the implementation of a Demand Response Management System ("DRMS"), which will evolve into a Distributed Energy Resource Management System ("DERMS"), resulting in the Companies' recent implementation of the DEMS[9] in Docket No. 2015-0411 Decision and Order No. 34884. The ADMS will interface

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[8] See Docket No. 2017-0226, *Modernizing Hawai'i's Grid For Our Customers*, filed on August 29, 2017, Figures 10-12.

[9] Hawaiian Electric successfully implemented the Siemens Energy IP DEMS and went live with the DEMS on February 24, 2019.

with the DEMS in order to dispatch DR and DER resources. The DEMS will manage the customer- and aggregator-facing aspects of the available customer energy options, while the ADMS will manage the distribution system and dispatch DER as needed to meet grid needs. For example, as part of the Integrated Grid Planning ("IGP") process, the Companies are identifying areas where non-wired alternatives (NWA) could address capacity constraints across the system.[10] Once a NWA is implemented, the ADMS will monitor to determine when the dispatchable distributed resources (*e.g.*, Demand Response and/or Energy Storage) in those areas are needed to stay within the capacity rating of the infrastructure and coordinate with the DEMS to dispatch appropriately. Capacity ratings specify the physical limitations of the distribution infrastructure denoting the amount of electricity that can flow through the different components of the system. Exceeding these limits for a sustained period could lead to safety and/or reliability issues, such as the failure of a conductor or transformer. The ADMS will send a dispatch request to the DEMS when DER and/or DR capacity is needed. The DEMS will relay that command to the participating DER aggregator(s) and participating customers. Following dispatch, the advanced meters will provide interval data through the GMS Phase 1 MDMS to the DEMS to perform the measurement and verification ("M&V") on the customer-owned resources and the aggregated DER resource (or resources) as a whole.

E. SYSTEM INTEGRATION

The system integration effort to enable the interfaces between ADMS, EMS, DEMS, WMS, CIS, GIS, telecom gateway, meter head-end, and MDMS and other systems makes up a significant amount of the estimated Project cost. Figure 5 shows a high-level depiction of these system interfaces from the National Institute of Standards and Technology ("NIST") Domain and Logical Model for Grid Information Networks framework.[11] The color-coded legend illustrates how investments being made from different dockets combine together to provide the core cyber-physical grid platform technology envisioned in the GMS.

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[10] See https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/distribution-planning-and-grid-services-documents.

[11] See National Institute of Standards and Technology ("NIST") Framework and Roadmap of Smart Grid Interoperability Standards, Section 5.3 Smart Grid Architecture Model: https://www.nist.gov/engineering-laboratory/smart-grid/framework-and-road-map-smart-grid-interoperability

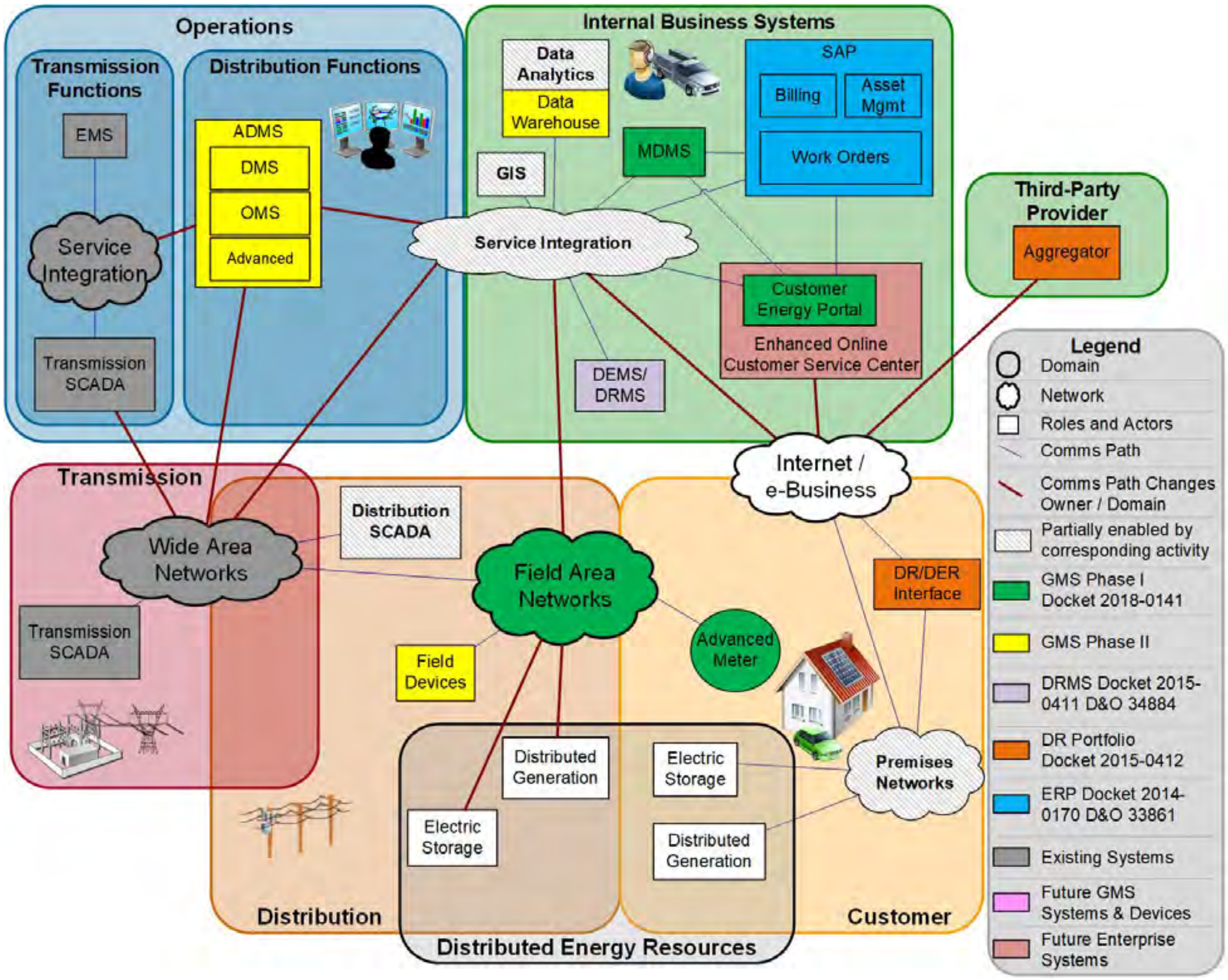

Figure 5

II. CYBERSECURITY AND PRIVACY FOR GRID MODERNIZATION STRATEGY IMPLEMENTATION

The protection of business and customer information is a serious undertaking for the Hawaiian Electric Companies. This is especially true as the Companies transform into the modern utility of the future that utilizes "smart" technologies leveraging seamless connectivity and information more effectively than ever before. With this increase in network connectivity and use of information, there is also an increase in attempted cyber-attacks as adversarial activity becomes more common and sophisticated. Such attacks, when left unchecked, could lead to the loss of customer and/or business data that leads to potential privacy issues, financial losses, and/or even damage to the grid infrastructure itself.

To effectively manage the risk presented by these new vulnerabilities and limit any further exposure of existing vulnerabilities, the Companies' GMS implementation will enhance and add new cybersecurity solutions that are designed to protect, detect, and manage such threats so that they are prevented and/or responded to with immediacy. This will be accomplished as part of an established cyber security programmatic practice aligned with the National Institute of Standards and Technology ("NIST") Cyber Security Framework ("CSF"). Risk mitigation measures will include fortifying existing mitigations such as multi-level access controls, anti-malware solutions, and a variety of intrusion detection sensors monitored by a dedicated operations security center, while providing for additional security zones, more rigorous data management, and security information and event management capabilities. As discussed below, this combination of new and incremental cybersecurity capabilities along with monitoring and management practices will facilitate grid modernization in a safe and secured environment.

A. GMS IMPLICATIONS FOR CYBERSECURITY

GMS technologies will make the enterprise systems more complex, with new applications, network access points and data introduced into operations. The GMS Project includes installation of advanced metering and telecommunications to support devices as well as additional computing systems such as a Meter Data Management System ("MDMS") and Advanced Distribution Management System ("ADMS") that add new functionality to the grid. All of these changes will present potential vulnerabilities, both known and unknown.[12] With the implementation of multiple GMS systems and the more robust and bidirectional data exchanges throughout the enterprise, threats, vulnerabilities, and impact will all increase at a substantially higher rate. This means cybersecurity-related risks will also substantially increase.

The systems to be implemented as part of the GMS are not simply new versions of old systems. The Companies will be integrating new types of systems, and these systems will add connectivity and data at the service location endpoints and through the distribution level of the grid. This represents an unprecedented and new capability that converges information technology ("IT") and operational technology ("OT") networks.[13] For instance, advanced meters will now provide usage and operational data from the service location endpoint to both a centralized MDMS for billing purposes as well as grid management systems like the ADMS used to provide for higher concentrations of renewable energy at the distribution level.

These systems will be a hybrid that combines capabilities and data exchanges of traditional business systems with those occurring on previously isolated control systems. Two-way data exchanges will be required for systems that were previously separate and "air-gapped," and security zones that currently allow only one-way connections will become bidirectional. Systems that were previously independent will now be interdependent.

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[12] The National Association of Regulatory Utility Commissioners ("NARUC") describes the Smart Grid cyber-security challenge in this way: "With the advent of smart grid technologies, which layer software on top of utility operations and computer systems, threats become increasingly likely and relevant." Cybersecurity for State Regulators 2.0, NARUC (2013).

[13] See John P. Roberts and Kristian Streenstrup, The Management Implications of IT/OT Convergence, Gartner Inc. (March 4, 2010).

The RF mesh Field Area Network ("FAN") installed as part of the GMS Project inherently expands the attack surface of the Companies' integrated data networks. This RF network will connect many more endpoints – by several orders of magnitude – than the legacy microwave and fiber optic Wide Area Network ("WAN") data links that the Companies have operated for many years. The addition of new GMS solutions into the OT control centers and IT data centers further complicates the task of protecting the overall infrastructure because of data exchange requirements across previously isolated network boundaries.

B. VULNERABILITIES OF GMS

Some of the types of vulnerabilities that could be exploited, causing risk to the reliability and operation of a GMS include: (1) critical infrastructure and (2) data.

1. Critical Infrastructure

GMS systems present new vulnerabilities that, if exploited, can have a significant impact on the operations of the electrical grid. These systems use interconnected elements that optimize the communications and control across energy generation, distribution, and consumption. However, the reality is that critical infrastructure in general, and electric grids in particular, are already prime targets for cyber-based attacks. Thus, as further described below, several risk mitigation activities are planned in addition to measures the Companies already have implemented, including additional network segmentation, cryptographic systems, and role-based access controls with stronger authentication.

2. Data

The traditional risk for utilities in data privacy is the risk of a data breach. Regardless of the root cause (e.g., accident, malicious insider, cybersecurity incident), data breaches pose the potential for a variety of harms, including direct financial harm, remediation costs for individuals, regulatory and legal actions, adverse publicity, and dissatisfied customers.[14]

Customer trust is important to the Companies and to the GMS implementation, because a loss of trust would directly affect customer participation and the ability to fully realize the goals and benefits of the GMS.[15] The amount of customer data entrusted to utility companies has expanded rapidly and continues to do so. As a result, the Companies have developed and the Commission approved a Customer Data Access and Privacy Policy.[16] Newer types of customer data are also captured through non-traditional customer interactions such as social media,

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[14] See Customer Data Access and Privacy Policy filed in Docket No. 2018-0141 on September 25, 2019
[15] Pursuant to D&O 36230, the Hawaiian Electric Companies hosted a two-day workshop on customer data access and privacy on July 16 and 17, 2019.
[16] See Docket No. 2018-0141 Order 37146 Accepting the Companies' Customer Data Access and Privacy Policy

alternative billing and payment methods, and responses to a wider variety of voluntary programs in the areas of demand response.

C. GMS CYBERSECURITY SAFEGUARDS

GMS implementation will require the Companies' cybersecurity protective measures and controls to be more comprehensive and standardized to industry best practices. Among the risk mitigations planned for the GMS Project are increased data network segmentation (to isolate components), additional intrusion sensors with related security event logging/analysis, additional data encryption, penetration tests, third-party security risk assessments, and tighter processes to restrict data access. Securely enabling these new grid capabilities and customer enhancements will require additional investment in cybersecurity controls for the data networks.

The Companies have experience in taking proactive steps to protect against cyber-attacks and unwarranted intrusions. Some components of the Itron (formerly known as Silver Spring Networks) Enhanced Security Package were implemented during the Companies' Smart Grid Initial Phase demonstration project ("Initial Phase") on O'ahu, at that time becoming one of the first utilities nationwide to utilize this enhanced level of security software. This industry leading security measure introduced more comprehensive data security processes and intrusion detection systems designed to specifically address the information traversing the mesh network, such as that communicated between advanced meters and utility back office systems. The Companies plan to continue to utilize similar enhanced features, along with additional layers of protection as they implement the GMS Project throughout their service territories.

The Companies' existing and planned security and privacy measures, including programmatic alignment with the NIST CSF to effectively manage these safeguards and controls, coupled with the advanced technology solutions will result in a robust, comprehensive cybersecurity risk mitigation framework that will guide the GMS implementation. This framework enables a unified approach in which the Companies can better prepare, prevent, and recover from potential incidents and ensure that customer and business information is adequately protected.

1. Cybersecurity Risk Mitigation Framework

The NIST *CSF*[17] describes five stages for its core risk mitigation functions: Identify, Protect, Detect, Respond, and Recover – each of which is discussed in turn below. Alignment with frameworks such as this helps illustrate how the Companies are addressing mitigations in a comprehensive manner. Collectively, these tools and processes represent a "defense-in-depth"[18] strategy. In addition to incorporating protection mechanisms, the Companies need to expect

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[17] Available at http://www.nist.gov/cyberframework/.

[18] Also known as *Castle Approach*, an information concept in which multiple layers of security controls (defense) are placed throughout an information technology system.

attacks and include attack detection tools and procedures to react to and recover from these attacks. The Companies also need to maintain a balance between the cyber protection capabilities, cost, performance, and operational considerations.

Identify

The *Identify* core function refers to developing the organizational understanding to manage cybersecurity risk to systems, assets, data, and capabilities. Standard risk identification strategies for complex computing environments include both penetration testing and security risk assessments, typically conducted by independent third parties. Penetration testing is a proactive measure to discover and exploit the security vulnerabilities within an IT or OT infrastructure. A security risk assessment is a comprehensive study to discover and describe risk in the form of threats, vulnerabilities, and impacts, and to recommend system-specific risk mitigations. Penetration tests and vulnerability assessments will be conducted by independent third parties during the GMS Project as part of the system development life cycle release process.

Protect

The *Protect* core function refers to developing and implementing the appropriate safeguards to ensure delivery of critical information and infrastructure. Within this function, there is the need for network segmentation, management for encryption and cryptographic keys utilized by advanced meters and other remote devices, and endpoint protection for the required servers and workstations that will harvest the information transmitted over the GMS' telecommunication network. Collectively, these will serve as additional layers of protection against unauthorized intrusions during the GMS Project.

Network Segmentation

With the solutions added for GMS Project, data will be generated and consumed in a far more integrated and enterprise-wide manner than before. Additional layers of security are required to provide greater defense-in-depth. In determining how to better protect the GMS systems, the Companies considered the underlying data system infrastructure – not just OT data systems or IT data systems, but all data systems regardless of function or physical location within the enterprise.

The introduction of advanced meters and Field Devices into the Companies' information and control systems environment creates many new data sets. It also creates a requirement for data exchanges across traditionally isolated data network environments. Advanced meter and Field Device integration will require enhanced data network segmentation in order to better protect the network environments from compromise.

Encryption and Cryptographic Key Management Systems

Hawai‘i law provides guidance for companies in the protection of customer data.[19] The Companies have implemented an encryption strategy designed to enhance protection of sensitive personally identifiable information at rest. This system is already in place but will need expansion to accommodate the new GMS systems.

Cryptographic key management systems ("CKMS") are used to generate, allocate, verify, and revoke credentials used to encrypt data and authenticate data sources on a network. With the integration of grid modernization systems, particularly advanced meters, the Companies will transition from managing a few thousand cryptographic keys to managing potentially millions of cryptographic keys. Each of the advanced meters will have multiple cryptographic key pairs; each pair will be used to protect different meter data sets and commands. Additional cryptographic certificates will be used to establish virtual private networks for purposes of protecting data in transit. Doing so will require investment in CKMS and staffing to manage these certificates across the Companies.

Endpoint Protection (Servers and Workstations)

The Companies utilize a variety of standard endpoint protection systems such as signature-based and behavioral-based malware detection systems. These capabilities will be extended to the GMS systems deployed during the GMS Project.

Detect

The *Detect* core function refers to developing and implementing the appropriate capabilities to identify the occurrence of a cyber-attack. These capabilities include network intrusion detection systems, a network and website scanning service, and a security incident event management system utilized by Hawaiian Electric's Network Operations and Security Center (NOSC) to continuously monitor and detect any events or incidents that may arise. As described in the Application, future phases of the GMS implementation include a Network Operations Center (NOC) needed to monitor and administer the telecommunications system. The Companies will explore the current capabilities of the NOSC to assess if an expansion of the NOSC would support the GMS implementation or if a separate NOC is required.

The Companies utilize a variety of commercially available devices to detect anomalous activity on their data networks that could indicate a network intrusion. Network intrusion detection system devices are continuously monitored by the NOSC personnel. The Companies also utilize a variety of commercially available systems to scan servers for detection of vulnerabilities in applications and operating systems. This includes software tools used by employees on site, as well as third-party service providers which scan the Companies' public-

[19] See Hawai‘i Revised Statutes, Chapter 487N (Security Breach of Personal Information law).

facing websites. Security control assessments are integrated in a continuous monitoring practice to ensure that safeguards and countermeasures remain effective in the Companies' ever-evolving operating and technological environments.

In addition, with the enhanced data network segmentation described above, there will be additional security zones from which to collect and correlate security events. This includes events from the additional firewalls to protect the perimeter of each zone, as well as events from the applications and other network appliances within the zones. Each of these devices creates an event log, and the log files are collected, aggregated, correlated, and analyzed by the NOSC to detect any potential incidents or attempted compromises that may occur.

Respond

The *Respond* core function refers to developing and implementing the appropriate activities in response to a known or suspected cyber-attack. Incident response programs specify actions to be taken when the Companies suspect or detect unauthorized access to customer information systems, including appropriate reports to government agencies. New capabilities to utilize forensic analysis tools and services are also being developed in order to improve the effectiveness of the incident response process. The Companies will extend these capabilities to their GMS systems.

Recover

The *Recover* core function refers to developing and implementing the appropriate activities to maintain plans for resilience and to restore any capabilities or services that may be impaired due to a cyber-attack. Recovery processes and policies are important to the restoration of capabilities or critical infrastructure services impaired during a cyber-attack. This includes coordination of communications necessary to support timely recovery and reduce the impact of an event. The Companies will continue to improve their infrastructure and systems architecture to better support both continuous operation and graceful degradation[20] in preparation of potential attacks, as well as resistance, resilience, and recovery after an attack. These capabilities will also be extended to GMS systems.

Some of the risk mitigation activities described above, such as anti-malware solutions and network scanning tools, are extensions of existing capabilities, which the Companies have had in place for several years. However, for some of the more substantial risk mitigation activities, such as the additional network segmentation, security information event management, encryption and cryptographic key management capabilities, additional investment will be required to adequately protect the more robust data and more complex grid infrastructure required by the GMS.

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[20] Graceful degradation is the tactical response of a computer or network to maintain limited functionality if a portion of the system has been rendered inoperative in order to prevent catastrophic failure.

III. CONCLUSION

The Companies understand and are vigilant about mitigating the risks posed by the implementation of GMS technologies. Customer information and privacy is one of the Companies' highest priorities. That is why in addition to their existing cybersecurity systems, the Companies have matured the cyber security program by leveraging NIST CSF, and extensively prepared operational configurations to accommodate the need for additional infrastructure required to protect against any unauthorized intrusions or cyber-based attacks on a modernized grid. It is through a robust privacy framework, coupled with informed customers, that customer data will be protected. In connection with the GMS Project, there will be ongoing assessments, testing, and evaluation of the services and processes in place to ensure that changes in cybersecurity and privacy protection measures are adequately maintained, and that all customer, legal, and regulatory requirements are met. As new threats or vulnerabilities emerge, the Companies will implement commensurate risk-based measures to enable the additional demands of data management and privacy procedures while ensuring customer information is adequately protected.

Exhibit G

Grid Modernization Strategy Phase 2 ADMS and Field Devices Application

Updated GMS Phase 2 Project Costs

PROJECT COST ESTIMATE

Project Title: GMS Phase 2 ADMS - Updated 3/31/21
Budget Item: **See Below**

	CONSOLIDATED				
	Pre-Implementation	Implementation			Annual On-Going
		CAPITAL	DEFERRED	O&M	
OTHER (HARDWARE)		$ 1,242,001			
LABOR (INCREMENTAL)			$ 3,407,160		$ 840,999
OUTSIDE SERVICES	$ 300,000.00	$ 837,360	$ 26,355,033	$ 10,543,832	$ 875,000
OVERHEAD		$ 274,340	$ 2,371,594	$ 1,983,665	$ 886,290
AFUDC			$ 2,328,638		
SUBTOTAL	$ 300,000	$ 2,353,701	$ 34,462,425	$ 12,527,497	$ 2,602,289
ESTIMATED CONTRIBUTIONS	$ -	$ -			$ -
NET PROJECT COST	$ 300,000	$ 2,353,701	$ 34,462,425	$ 12,527,497	$ 2,602,289
TOTAL PROJECT COST	Pre-Implementation + Implementation			$ 49,643,623	

PROJECT COST ESTIMATE

Project Title: GMS Phase 2 ADMS - Updated 3/31/21
Budget Item: **See Below**

	Pre-Implementation **HECO**	**Implementation** **HECO**	**Annual On-Going** **HECO**	**Pre-Implementation** **HELCO**	**Implementation** **HELCO**	**Annual On-Going** **HELCO**	**Pre-Implementation** **MECO**	**Implementation** **MECO**	**Annual On-Going** **MECO**
LABOR (INCREMENTAL)		$ 1,566,600	$ 374,001		$ 920,280	$ 233,499		$ 920,280	$ 233,499
MATERIALS									
OUTSIDE SERVICES	$ 100,000	$ 18,724,006	$ 599,000	$ 100,000	$ 9,553,490	$ 138,000	$ 100,000	$ 9,458,729	$ 138,000
OTHER (HARDWARE)		$ 631,000			$ 305,001			$ 306,000	
OVERHEAD		$ 2,070,821	$ 391,508		$ 1,575,439	$ 229,199		983,339	265,583
AFUDC		$ 1,291,742			$ 521,805			$ 515,091	
TOTAL COST OF PROJECT	$ 100,000	$ 24,284,169	$ 1,364,509	$ 100,000	$ 12,876,015	$ 600,698	$ 100,000	$ 12,183,439	$ 637,082
ESTIMATED CONTRIBUTIONS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NET PROJECT COST	$ 100,000	$ 24,284,169	$ 1,364,509	$ 100,000	$ 12,876,015	$ 600,698	$ 100,000	$ 12,183,439	$ 637,082

Group	Hours							Dollars						
· Updated 3/31/21	Implementaion	Annual On-Going	Implementaion	Annual On-Going	Implementaion	Annual On-Going		Implementaion	Annual On-Going	Implementaion	Annual On-Going	Implementaion	Annual On-Going	
	HECO	HECO	HELCO	HELCO	MECO	MECO		HECO	HECO	HELCO	HELCO	MECO	MECO	
														-
(PES)	17,490		3,238	994	5,675	778	28,175	826,800		150,240	47,499	327,480	47,499	1,399,518
(PRH)	7,884	1,927					9,811	375,000	95,001					470,001
(PRZ)	7,670	1,886						364,800	93,000					
erations (PRD)		3,772							186,000					
							-							-
(HRP)			12812	2113			14,925			582,240	101,001			683,241
(HRT)			4582	1974						187,800	84,999			
							-							-
(MOA)					7078	1654	8,732					405,000	101,001	506,001
(MRT)					4324	1976	6,300					187,800	84,999	272,799
							-							-
	33,044	7,585	20,632	5,081	17,077	4,408	87,827	1,566,600	374,001	920,280	233,499	920,280	233,499	4,248,159

Project Title: GMS Phase 2 Field Devices
Budget Item: See Below

Consolidated			
	Implementation	Total O&M	Annual On-Going O&M
Labor (incremental)	[redacted]		
Materials	[redacted]	[redacted]	[redacted]
Outside Services	[redacted]	[redacted]	[redacted]
Overhead	[redacted]	[redacted]	[redacted]
AFUDC	$2,844,219		
Total Cost of the Project	$53,703,361	$1,007,160	$363,543
Estimated Contributions			
Net Project Costs	$53,703,361	$1,007,160	$363,543

Hawaiian Electric			
	Implementation	Total O&M	Annual On-Going O&M
Labor (incremental)	[redacted]		
Materials	[redacted]	[redacted]	[redacted]
Outside Services	[redacted]	[redacted]	[redacted]
Overhead	[redacted]	[redacted]	[redacted]
AFUDC	$2,276,735		
Total Cost of the Project	$33,810,467	$646,956	$ 221,661
Estimated Contributions			
Net Project Costs	$33,810,467	$646,956	$ 221,661

Hawai'i Electric Light			
	Implementation	Total O&M	Annual On-Going O&M
Labor (incremental)	[redacted]		
Materials	[redacted]	[redacted]	[redacted]
Outside Services	[redacted]	[redacted]	[redacted]
Overhead	[redacted]	[redacted]	[redacted]
AFUDC	$220,081		
Total Cost of the Project	$6,889,216	$ 194,793	$72,529
Estimated Contributions			
Net Project Costs	$6,889,216	$ 194,793	$72,529

Maui Electric			
	Implementation	Total O&M	Annual On-Going O&M
Labor (incremental)	[redacted]		
Materials	[redacted]	[redacted]	[redacted]
Outside Services	[redacted]	[redacted]	[redacted]
Overhead	[redacted]	[redacted]	[redacted]
AFUDC	$347,402		
Total Cost of the Project	$13,003,678	$165,411	$69,353
Estimated Contributions			
Net Project Costs	$13,003,678	$165,411	$69,353

Project Title: GMS Phase 2 Field Devices
Budget Item: Labor (incremental)

Group	Hours Implementation HECO	HELCO	MECO	TOTAL
H101010: Corporate				
101134S: Telecommunications Engineering (PEN)	10,422	1,390	3,359	15,171
101135S: Telecommunications Operations (PEO)	7,868	-	-	7,868
201135S: Telecommunications Operations	-	1,283	-	1,283
H201010: System Operations				
100006S: Admin-Sys Op (PRA)	110	110	110	330
100009S: Operating Planning (PRH)	14,872	-	-	14,872
200003S: Admin-Sys Ops/Sys Plng (HRA)	-	66	66	132
200004S: Plng-Sys Op/Sys Planning (HRP)	-	740	-	740
300002S: Dispatch - System Operations (MOD)	-	-	9,360	9,360
H202010: Energy Delivery				
100161S: ENGINEERING T&D ENG (PTD) HE	28,536	220	220	28,976
100171S: ENGINEERING SUBSTATION ENG (PBD)	2,792		892	3,684
100191S: PLNG & CONSTR PROG MGMT (PPD) HE	4,794	154	154	5,102
100210S: T&D OPERATIONS ADMIN (PZA) HE	110	-	-	110
100212S: T&D OPERATIONS (PZC) HE	19,553	-	-	19,553
100217S: T&D OPERATIONS PTM (PZH) HE	4,675	-	-	4,675
100221S: PLNG & CONSTR SVCS (PMB) HE	2,709	1,767	745	5,222
100233S: SUBST & METER RELAY (PRR) HE	15,096	-	-	15,096
100234S: SUBST & METER I&C (PQI) HE	3,493	-	-	3,493
100237S: SUBST & METER OP ADMIN (PQJ) HE	110	110	110	330
200171S: ENGINEERING SUBST ENG (HBD) HL	-	732	-	732
200202S: ENGINEERING T&D ENG (HTX) HL	-	3,188	-	3,188
200212S: T&D OPERATIONS HILO (HZC) HL	-	6,628	-	6,628
200214S: T&D OPERATIONS KONA (HZE) HL	-	226	-	226
200233S: SUBST & METER RELAY (HRR) HL	-	1,802	408	2,210
300171S: ENGINEERING SUBST ENG (MBD) ME	-	-	220	220
300202S: ENGINEERING T&D ENG (MTX) ME	-	-	16,190	16,190
300212S: T&D OPERATIONS MAUI (MZC) ME	-	-	6,598	6,598
300236S: SUBST & METER SUBST (MQS) ME	-	-	1,080	1,080
300237S: SUBST & METER OP ADMIN (MQJ) ME	-	-	4,282	4,282
H204010: Operations Other				
100126S: System Protection (PXR)	7,977	1,180	2,482	11,639
100501S: Admin-T&D Plng (PBB)	352	352	288	992
100503S: Distribution Plng (PBS)	1,388	-	-	1,388
100506S: Admin-Asset Plng & Strategy (PRK) - HE	88	88	88	264
100508S: Asset Programs (PRP) HE	16	88	88	192
100524S: Project Initialization (PPF) - HE	-	46	97	143
200503S: Distr Plng (HBS) - HL	-	529	-	529
300503S: Distr Plng (MBS) - ME	-	-	476	476
Total	124,961	20,699	47,314	192,973

[redacted]

Exhibit H

Grid Modernization Strategy Phase 2 ADMS and Field Device Application

Updated Bill Impact

REVENUE REQUIREMENTS AND BILL IMPACTS

The Hawaiian Electric Companies[1] performed a high level, economic analysis to forecast revenue requirements and bill impacts for the Advanced Distribution Management System ("ADMS") and Field Devices project components (collectively referred to as the "Project"), of the second phase ("Phase 2") of the Grid Modernization Strategy implementation. This high-level forecast uses broad or simplified assumptions for the purpose of estimating revenue requirements over the life of the investment and a typical monthly residential bill impact. Actual results may differ based on the application of specific rules and on the actual costs incurred.

The ADMS forecast analysis assumed a typical residential customer uses 500kWh per month. ADMS bill impacts reflect a 17 year period for Phase 2. The forecasted bill impact excludes other future replacement costs. Beyond the ADMS and Field Devices components of Phase 2 (2026), 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 – ADMS Consolidated Revenue Requirement ($ in millions)

	Year	Hawaiian Electric	Hawaii Electric Light	Maui Electric	Consolidated
1	2022	1.69	1.07	0.97	3.73
2	2023	1.65	1.48	1.32	4.45
3	2024	3.43	1.59	1.49	6.51
4	2025	3.63	1.96	1.87	7.46
5	2026	3.00	2.07	1.89	6.96
6	2027	3.74	2.02	2.03	7.79
7	2028	3.62	1.94	1.95	7.51
8	2029	3.52	1.89	1.90	7.31
9	2030	3.43	1.84	1.85	7.12
10	2031	3.35	1.79	1.82	6.96
11	2032	3.27	1.76	1.78	6.81
12	2033	3.20	1.71	1.74	6.65
13	2034	3.12	1.68	1.70	6.50
14	2035	3.04	1.63	1.67	6.34
15	2036	1.93	1.25	1.29	4.47
16	2037	1.74	1.03	1.06	3.83
17	2038	1.52	0.91	0.96	3.39
	Total	48.88	27.62	27.29	103.79
	NPV	28.49	16.16	15.82	60.47

Revenue Requirement rounded to the nearest $10,000

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

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

	Year	ADMS Capital Revenue Requirement[1]	ADMS Deferred Revenue Requirement[1]	Pre-Implementation O&M Revenue Requirement[1]	Implementation O&M Revenue Requirement[1]	Post-Implementation O&M Revenue Requirement[1]	OSI and OMS Benefits Revenue Requirement[2]	Total ADMS Revenue Requirement[1]	Sales Forecast[2] (MWh)	Rate Impact ¢/kWh		Bill Impact 500 kWh[3]
1	2022	[redacted]						1.69	6,328,325	0.0267	$	0.13
2	2023	[redacted]						1.65	6,366,292	0.0259	$	0.13
3	2024	[redacted]						3.43	6,441,818	0.0532	$	0.27
4	2025	[redacted]						3.63	6,520,703	0.0557	$	0.28
5	2026	[redacted]						3.00	6,599,300	0.0455	$	0.23
6	2027	[redacted]						3.74	6,611,700	0.0566	$	0.28
7	2028	[redacted]						3.62	6,645,400	0.0545	$	0.27
8	2029	[redacted]						3.52	6,681,300	0.0527	$	0.26
9	2030	[redacted]						3.43	6,753,400	0.0508	$	0.25
10	2031	[redacted]						3.35	6,787,600	0.0494	$	0.25
11	2032	[redacted]						3.27	6,823,700	0.0479	$	0.24
12	2033	[redacted]						3.20	6,878,700	0.0465	$	0.23
13	2034	[redacted]						3.12	6,922,700	0.0451	$	0.23
14	2035	[redacted]						3.04	6,977,200	0.0436	$	0.22
15	2036	[redacted]						1.93	7,058,300	0.0273	$	0.14
16	2037	[redacted]						1.74	7,111,800	0.0245	$	0.12
17	2038	[redacted]						1.52	7,185,800	0.0212	$	0.11
Total		[redacted]						48.88		*Average*	$	0.21
NPV @	6.88%	1.12	16.22	0.10	5.19	9.44	(3.58)	28.49				

Notes:
1. Revenue Requirement rounded to the nearest $10,000.
2. Estimated Hawaiian Electric Sales in MWH.
3. Hawaiian Electric typical residential energy consumption, per month.

Table 3 – ADMS Hawai'i Electric Light Revenue Requirement ($ in millions) and Bill Impact

	Year	ADMS Capital Revenue Requirement[1]	ADMS Deferred Revenue Requirement[1]	Pre-Implementation O&M Revenue Requirement[1]	Implementation O&M Revenue Requirement[1]	Post-Implementation O&M Revenue Requirement[1]	OSI and OMS Benefits Revenue Requirement[2]	Total ADMS Revenue Requirement[1]	Sales Forecast[2] (MWh)	Rate Impact ¢/kWh		Bill Impact 500 kWh[3]
1	2022	[redacted]						1.07	987,618	0.1083	$	0.54
2	2023	[redacted]						1.48	989,103	0.1496	$	0.75
3	2024	[redacted]						1.59	992,000	0.1603	$	0.80
4	2025	[redacted]						1.96	990,370	0.1979	$	0.99
5	2026	[redacted]						2.07	984,705	0.2102	$	1.05
6	2027	[redacted]						2.02	979,927	0.2061	$	1.03
7	2028	[redacted]						1.94	982,973	0.1974	$	0.99
8	2029	[redacted]						1.89	978,219	0.1932	$	0.97
9	2030	[redacted]						1.84	977,491	0.1882	$	0.94
10	2031	[redacted]						1.79	977,693	0.1831	$	0.92
11	2032	[redacted]						1.76	980,258	0.1795	$	0.90
12	2033	[redacted]						1.71	978,330	0.1748	$	0.87
13	2034	[redacted]						1.68	981,199	0.1712	$	0.86
14	2035	[redacted]						1.63	988,996	0.1648	$	0.82
15	2036	[redacted]						1.25	999,038	0.1251	$	0.63
16	2037	[redacted]						1.03	1,005,152	0.1025	$	0.51
17	2038	[redacted]						0.91	1,013,498	0.0898	$	0.45
Total		[redacted]						27.62		*Average*	$	0.82
NPV @	7.00%	0.68	7.87	0.10	3.40	4.11	-	16.16				

Notes:
1. Revenue Requirement rounded to the nearest $10,000.
2. Estimated Hawaii Electric Light Sales in MWH.
3. Hawaii Electric Light typical residential energy consumption, per month.

Table 4 – ADMS Maui Electric Revenue Requirement ($ in millions) and Bill Impact

	Year	ADMS Capital Revenue Requirement[1]	ADMS Deferred Revenue Requirement[1]	Pre-Implementation O&M Revenue Requirement[1]	Implementation O&M Revenue Requirement[1]	Post-Implementation O&M Revenue Requirement[1]	OSI and OMS Benefits Revenue Requirement[2]	**Total ADMS Revenue Requirement[1]**	Sales Forecast[2] (MWh)	Rate Impact ¢/kWh		**Bill Impact 500 kWh[3]**
1	2022	[redacted]						**0.97**	999,545	0 0970	**$**	**0.49**
2	2023							**1.32**	991,318	0.1332	**$**	**0.67**
3	2024							**1.49**	998,297	0.1493	**$**	**0.75**
4	2025							**1.87**	1,002,118	0.1866	**$**	**0.93**
5	2026							**1.89**	1,010,939	0.1870	**$**	**0.93**
6	2027							**2.03**	1,020,115	0.1990	**$**	**0.99**
7	2028							**1.95**	1,028,293	0.1896	**$**	**0.95**
8	2029							**1.90**	1,031,130	0.1843	**$**	**0.92**
9	2030							**1.85**	1,038,344	0.1782	**$**	**0.89**
10	2031							**1.82**	1,047,022	0.1738	**$**	**0.87**
11	2032							**1.78**	1,062,522	0.1675	**$**	**0.84**
12	2033							**1.74**	1,079,158	0.1612	**$**	**0.81**
13	2034							**1.70**	1,097,114	0.1550	**$**	**0.77**
14	2035							**1.67**	1,116,863	0.1495	**$**	**0.75**
15	2036							**1.29**	1,141,138	0.1130	**$**	**0.57**
16	2037							**1.06**	1,159,595	0 0914	**$**	**0.46**
17	2038							**0.96**	1,183,049	0 0811	**$**	**0.41**
Total								**27.29**		*Average*	**$**	**0.76**
NPV @	6 94%	0.63	7.74	0.10	2.97	4 38	-	**15.82**				

Notes:
1. Revenue Requirement rounded to the nearest $10,000.
2. Estimated Maui Electric Sales in MWH.
3. Maui Electric typical residential energy consumption, per month.

The Field Devices forecast analysis assumed a typical residential customer uses 500kWh per month. Field Devices bill impacts reflect a 56 year period for Phase 2. The forecasted bill impact excludes other future replacement costs. Beyond the Field Devices component of Phase 2 (2026), 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 5 – Field Devices Consolidated Revenue Requirement ($ in millions)

	Year	Hawaiian Electric	Hawaii Electric Light	Maui Electric	Consolidated
1	2022	-	-	-	-
2	2023	0.46	0.14	0.19	0.79
3	2024	1.17	0.29	0.43	1.89
4	2025	2.16	0.51	0.82	3.49
5	2026	3.30	0.78	1.26	5.34
6	2027	4.20	0.99	1.61	6.80
7	2028	4.09	0.96	1.56	6.61
8	2029	3.98	0.93	1.52	6.43
9	2030	3.87	0.90	1.48	6.25
10	2031	3.77	0.87	1.44	6.08
11	2032	3.67	0.85	1.40	5.92
12	2033	3.59	0.82	1.37	5.78
13	2034	3.51	0.80	1.34	5.65
14	2035	3.45	0.78	1.31	5.54
15	2036	3.38	0.76	1.29	5.43
16	2037	3.24	0.69	1.23	5.16
17	2038	3.08	0.63	1.18	4.89
18	2039	2.90	0.55	1.12	4.57
19	2040	2.72	0.46	1.06	4.24
20	2041	2.56	0.39	1.01	3.96
21	2042	2.49	0.38	0.98	3.85
22	2043	2.42	0.38	0.94	3.74
23	2044	2.35	0.37	0.91	3.63
24	2045	2.29	0.36	0.89	3.54
25	2046	2.24	0.36	0.86	3.46
26	2047	2.20	0.36	0.84	3.40
27	2048	2.16	0.35	0.82	3.33
28	2049	2.12	0.35	0.80	3.27
29	2050	2.08	0.35	0.78	3.21
30	2051	2.04	0.34	0.76	3.14
31	2052	1.98	0.33	0.73	3.04
32	2053	1.91	0.33	0.69	2.93
33	2054	1.84	0.33	0.63	2.80
34	2055	1.76	0.33	0.58	2.67
35	2056	1.69	0.32	0.53	2.54
36	2057	1.66	0.32	0.52	2.50
37	2058	1.63	0.32	0.52	2.47
38	2059	1.61	0.32	0.51	2.44
39	2060	1.58	0.32	0.50	2.40
40	2061	1.56	0.31	0.49	2.36
41	2062	1.53	0.31	0.48	2.32
42	2063	1.50	0.31	0.47	2.28
43	2064	1.48	0.31	0.47	2.26
44	2065	1.45	0.31	0.46	2.22
45	2066	1.43	0.30	0.45	2.18
46	2067	1.40	0.30	0.44	2.14
47	2068	1.38	0.30	0.43	2.11
48	2069	1.35	0.30	0.43	2.08
49	2070	1.33	0.30	0.42	2.05
50	2071	1.31	0.30	0.41	2.02
51	2072	1.28	0.29	0.40	1.97
52	2073	1.26	0.29	0.40	1.95
53	2074	1.24	0.29	0.39	1.92
54	2075	1.18	0.29	0.37	1.84
55	2076	1.07	0.27	0.34	1.68
56	2077	0.94	0.26	0.29	1.49
57	2078	0.79	0.24	0.25	1.28
	Total	120.63	24.90	43.80	189.33
	NPV	35.87	7.69	13.50	57.06

Revenue Requirement rounded to the nearest $10,000

Table 6 – Field Devices Hawaiian Electric Revenue Requirement ($ in millions) and Bill Impact

	Year	Line Sensors Revenue Requirement[1]	RFI Revenue Requirement[1]	SVC Revenue Requirement[1]	Intelligent Switches Revenue Requirement[1]	O&M Revenue Requirement[1]	Total Field Devices Revenue Requirement[1]	Sales Forecast[2] (MWh)	Rate Impact ¢/kWh	Bill Impact 500 kWh[3]
1	2022	[redacted]					-	6,328,325	0.0000	$ -
2	2023						0.45	6,366,292	0.0071	$ 0.04
3	2024						1.18	6,441,818	0.0183	$ 0.09
4	2025						2.16	6,520,703	0.0331	$ 0.17
5	2026						3.29	6,599,300	0.0499	$ 0.25
6	2027						4.19	6,611,700	0.0634	$ 0.32
7	2028						4.09	6,645,400	0.0615	$ 0.31
8	2029						3.98	6,681,300	0.0596	$ 0.30
9	2030						3.88	6,753,400	0.0575	$ 0.29
10	2031						3.77	6,787,600	0.0555	$ 0.28
11	2032						3.67	6,823,700	0.0538	$ 0.27
12	2033						3.58	6,878,700	0.0520	$ 0.26
13	2034						3.51	6,922,700	0.0507	$ 0.25
14	2035						3.45	6,977,200	0.0494	$ 0.25
15	2036						3.38	7,058,300	0.0479	$ 0.24
16	2037						3.24	7,111,800	0.0456	$ 0.23
17	2038						3.08	7,185,800	0.0429	$ 0.21
18	2039						2.90	7,285,800	0.0398	$ 0.20
19	2040						2.71	7,431,700	0.0365	$ 0.18
20	2041						2.56	7,512,000	0.0341	$ 0.17
21	2042						2.49	7,637,300	0.0326	$ 0.16
22	2043						2.41	7,776,400	0.0310	$ 0.15
23	2044						2.35	7,945,400	0.0296	$ 0.15
24	2045						2.29	8,079,300	0.0283	$ 0.14
25	2046						2.24	8,237,100	0.0272	$ 0.14
26	2047						2.19	8,396,300	0.0261	$ 0.13
27	2048						2.16	8,574,400	0.0252	$ 0.13
28	2049						2.12	8,695,600	0.0244	$ 0.12
29	2050						2.08	8,822,300	0.0236	$ 0.12
30	2051						2.03	8,822,300	0.0230	$ 0.12
31	2052						1.99	8,822,300	0.0226	$ 0.11
32	2053						1.92	8,822,300	0.0218	$ 0.11
33	2054						1.85	8,822,300	0.0210	$ 0.10
34	2055						1.75	8,822,300	0.0198	$ 0.10
35	2056						1.69	8,822,300	0.0192	$ 0.10
36	2057						1.66	8,822,300	0.0188	$ 0.09
37	2058						1.63	8,822,300	0.0185	$ 0.09
38	2059						1.61	8,822,300	0.0182	$ 0.09
39	2060						1.58	8,822,300	0.0179	$ 0.09
40	2061						1.56	8,822,300	0.0177	$ 0.09
41	2062						1.53	8,822,300	0.0173	$ 0.09
42	2063						1.51	8,822,300	0.0171	$ 0.09
43	2064						1.48	8,822,300	0.0168	$ 0.08
44	2065						1.46	8,822,300	0.0165	$ 0.08
45	2066						1.43	8,822,300	0.0162	$ 0.08
46	2067						1.41	8,822,300	0.0160	$ 0.08
47	2068						1.38	8,822,300	0.0156	$ 0.08
48	2069						1.36	8,822,300	0.0154	$ 0.08
49	2070						1.33	8,822,300	0.0151	$ 0.08
50	2071						1.30	8,822,300	0.0147	$ 0.07
51	2072						1.28	8,822,300	0.0145	$ 0.07
52	2073						1.25	8,822,300	0.0142	$ 0.07
53	2074						1.24	8,822,300	0.0141	$ 0.07
54	2075						1.18	8,822,300	0.0134	$ 0.07
55	2076						1.07	8,822,300	0.0121	$ 0.06
56	2077						0.93	8,822,300	0.0105	$ 0.05
57	2078						0.79	8,822,300	0.0090	$ 0.04
Total							120.60		*Average*	$ 0.14
NPV @	6.88%	3.91	0.60	4.51	23.23	3.62	35.87			

Notes:
1. Revenue Requirement rounded to the nearest $10,000.
2. Estimated Hawaiian Electric Sales in MWH. Using 2050 forecasted sales for years thereafter.
3. Hawaiian Electric typical residential energy consumption, per month.

Table 7 – Field Devices Hawai‘i Electric Light Revenue Requirement ($ in millions) and Bill Impact

	Year	Line Sensors Revenue Requirement[1]	RFI Revenue Requirement[1]	SVC Revenue Requirement[1]	Intelligent Switches Revenue Requirement[1]	O&M Revenue Requirement[1]	**Total Field Devices Revenue Requirement[1]**	Sales Forecast[2] (MWh)	Rate Impact ¢/kWh		**Bill Impact 500 kWh[3]**
1	2022	[redacted]					**-**	987,618	0.0000	**$**	**-**
2	2023	[redacted]					**0.15**	989,103	0.0152	**$**	**0.08**
3	2024	[redacted]					**0.29**	992,000	0.0292	**$**	**0.15**
4	2025	[redacted]					**0.52**	990,370	0.0525	**$**	**0.26**
5	2026	[redacted]					**0.78**	984,705	0.0792	**$**	**0.40**
6	2027	[redacted]					**1.00**	979,927	0.1020	**$**	**0.51**
7	2028	[redacted]					**0.97**	982,973	0.0987	**$**	**0.49**
8	2029	[redacted]					**0.94**	978,219	0.0961	**$**	**0.48**
9	2030	[redacted]					**0.90**	977,491	0.0921	**$**	**0.46**
10	2031	[redacted]					**0.88**	977,693	0.0900	**$**	**0.45**
11	2032	[redacted]					**0.85**	980,258	0.0867	**$**	**0.43**
12	2033	[redacted]					**0.82**	978,330	0.0838	**$**	**0.42**
13	2034	[redacted]					**0.80**	981,199	0.0815	**$**	**0.41**
14	2035	[redacted]					**0.78**	988,996	0.0789	**$**	**0.39**
15	2036	[redacted]					**0.76**	999,038	0.0761	**$**	**0.38**
16	2037	[redacted]					**0.69**	1,005,152	0.0686	**$**	**0.34**
17	2038	[redacted]					**0.62**	1,013,498	0.0612	**$**	**0.31**
18	2039	[redacted]					**0.54**	1,023,641	0.0528	**$**	**0.26**
19	2040	[redacted]					**0.45**	1,038,353	0.0433	**$**	**0.22**
20	2041	[redacted]					**0.40**	1,047,686	0.0382	**$**	**0.19**
21	2042	[redacted]					**0.39**	1,063,080	0.0367	**$**	**0.18**
22	2043	[redacted]					**0.38**	1,081,157	0.0351	**$**	**0.18**
23	2044	[redacted]					**0.37**	1,101,904	0.0336	**$**	**0.17**
24	2045	[redacted]					**0.36**	1,120,098	0.0321	**$**	**0.16**
25	2046	[redacted]					**0.37**	1,141,820	0.0324	**$**	**0.16**
26	2047	[redacted]					**0.36**	1,166,350	0.0309	**$**	**0.15**
27	2048	[redacted]					**0.35**	1,193,827	0.0293	**$**	**0.15**
28	2049	[redacted]					**0.35**	1,216,317	0.0288	**$**	**0.14**
29	2050	[redacted]					**0.35**	1,243,754	0.0281	**$**	**0.14**
30	2051	[redacted]					**0.35**	1,243,754	0.0281	**$**	**0.14**
31	2052	[redacted]					**0.33**	1,243,754	0.0265	**$**	**0.13**
32	2053	[redacted]					**0.33**	1,243,754	0.0265	**$**	**0.13**
33	2054	[redacted]					**0.33**	1,243,754	0.0265	**$**	**0.13**
34	2055	[redacted]					**0.33**	1,243,754	0.0265	**$**	**0.13**
35	2056	[redacted]					**0.32**	1,243,754	0.0257	**$**	**0.13**
36	2057	[redacted]					**0.32**	1,243,754	0.0257	**$**	**0.13**
37	2058	[redacted]					**0.32**	1,243,754	0.0257	**$**	**0.13**
38	2059	[redacted]					**0.32**	1,243,754	0.0257	**$**	**0.13**
39	2060	[redacted]					**0.31**	1,243,754	0.0249	**$**	**0.12**
40	2061	[redacted]					**0.32**	1,243,754	0.0257	**$**	**0.13**
41	2062	[redacted]					**0.31**	1,243,754	0.0249	**$**	**0.12**
42	2063	[redacted]					**0.31**	1,243,754	0.0249	**$**	**0.12**
43	2064	[redacted]					**0.31**	1,243,754	0.0249	**$**	**0.12**
44	2065	[redacted]					**0.31**	1,243,754	0.0249	**$**	**0.12**
45	2066	[redacted]					**0.30**	1,243,754	0.0241	**$**	**0.12**
46	2067	[redacted]					**0.31**	1,243,754	0.0249	**$**	**0.12**
47	2068	[redacted]					**0.30**	1,243,754	0.0241	**$**	**0.12**
48	2069	[redacted]					**0.30**	1,243,754	0.0241	**$**	**0.12**
49	2070	[redacted]					**0.30**	1,243,754	0.0241	**$**	**0.12**
50	2071	[redacted]					**0.30**	1,243,754	0.0241	**$**	**0.12**
51	2072	[redacted]					**0.29**	1,243,754	0.0233	**$**	**0.12**
52	2073	[redacted]					**0.29**	1,243,754	0.0233	**$**	**0.12**
53	2074	[redacted]					**0.29**	1,243,754	0.0233	**$**	**0.12**
54	2075	[redacted]					**0.29**	1,243,754	0.0233	**$**	**0.12**
55	2076	[redacted]					**0.27**	1,243,754	0.0217	**$**	**0.11**
56	2077	[redacted]					**0.25**	1,243,754	0.0201	**$**	**0.10**
57	2078	[redacted]					**0.24**	1,243,754	0.0193	**$**	**0.10**
Total		[redacted]					**24.97**		*Average*	**$**	**0.21**
NPV @	7.00%	1.29	1.75	0.18	3 33	1.14	**7.69**				

Notes:
1. Revenue Requirement rounded to the nearest $10,000.
2. Estimated Hawaii Electric Light Sales in MWH. Using 2050 forecasted sales for years thereafter.
3. Hawaii Electric Light typical residential energy consumption, per month.

Table 8 – Field Devices Maui Electric Revenue Requirement ($ in millions) and Bill Impact

	Year	Line Sensors Revenue Requirement[1]	RFI Revenue Requirement[1]	SVC Revenue Requirement[1]	Intelligent Switches Revenue Requirement[1]	O&M Revenue Requirement[1]	Total Field Devices Revenue Requirement[1]	Sales Forecast[2] (MWh)	Rate Impact ¢/kWh	Bill Impact 500 kWh[3]
1	2022	[redacted]					-	999,545	0.0000	$ -
2	2023						0.19	991,318	0.0192	$ 0.10
3	2024						0.43	998,297	0.0431	$ 0.22
4	2025						0.82	1,002,118	0.0818	$ 0.41
5	2026						1.26	1,010,939	0.1246	$ 0.62
6	2027						1.61	1,020,115	0.1578	$ 0.79
7	2028						1.57	1,028,293	0.1527	$ 0.76
8	2029						1.53	1,031,130	0.1484	$ 0.74
9	2030						1.48	1,038,344	0.1425	$ 0.71
10	2031						1.45	1,047,022	0.1385	$ 0.69
11	2032						1.40	1,062,522	0.1318	$ 0.66
12	2033						1.38	1,079,158	0.1279	$ 0.64
13	2034						1.34	1,097,114	0.1221	$ 0.61
14	2035						1.32	1,116,863	0.1182	$ 0.59
15	2036						1.29	1,141,138	0.1130	$ 0.57
16	2037						1.22	1,159,595	0.1052	$ 0.53
17	2038						1.17	1,183,049	0.0989	$ 0.49
18	2039						1.12	1,206,540	0.0928	$ 0.46
19	2040						1.07	1,233,460	0.0867	$ 0.43
20	2041						1.01	1,252,621	0.0806	$ 0.40
21	2042						0.98	1,276,873	0.0768	$ 0.38
22	2043						0.94	1,301,261	0.0722	$ 0.36
23	2044						0.92	1,326,542	0.0694	$ 0.35
24	2045						0.88	1,346,119	0.0654	$ 0.33
25	2046						0.86	1,368,490	0.0628	$ 0.31
26	2047						0.84	1,390,776	0.0604	$ 0.30
27	2048						0.83	1,416,795	0.0586	$ 0.29
28	2049						0.81	1,435,501	0.0564	$ 0.28
29	2050						0.78	1,458,616	0.0535	$ 0.27
30	2051						0.76	1,458,616	0.0521	$ 0.26
31	2052						0.72	1,458,616	0.0494	$ 0.25
32	2053						0.69	1,458,616	0.0473	$ 0.24
33	2054						0.63	1,458,616	0.0432	$ 0.22
34	2055						0.58	1,458,616	0.0398	$ 0.20
35	2056						0.54	1,458,616	0.0370	$ 0.19
36	2057						0.53	1,458,616	0.0363	$ 0.18
37	2058						0.51	1,458,616	0.0350	$ 0.17
38	2059						0.50	1,458,616	0.0343	$ 0.17
39	2060						0.50	1,458,616	0.0343	$ 0.17
40	2061						0.49	1,458,616	0.0336	$ 0.17
41	2062						0.48	1,458,616	0.0329	$ 0.16
42	2063						0.48	1,458,616	0.0329	$ 0.16
43	2064						0.47	1,458,616	0.0322	$ 0.16
44	2065						0.46	1,458,616	0.0315	$ 0.16
45	2066						0.44	1,458,616	0.0302	$ 0.15
46	2067						0.44	1,458,616	0.0302	$ 0.15
47	2068						0.43	1,458,616	0.0295	$ 0.15
48	2069						0.42	1,458,616	0.0288	$ 0.14
49	2070						0.42	1,458,616	0.0288	$ 0.14
50	2071						0.41	1,458,616	0.0281	$ 0.14
51	2072						0.41	1,458,616	0.0281	$ 0.14
52	2073						0.40	1,458,616	0.0274	$ 0.14
53	2074						0.38	1,458,616	0.0261	$ 0.13
54	2075						0.37	1,458,616	0.0254	$ 0.13
55	2076						0.34	1,458,616	0.0233	$ 0.12
56	2077						0.29	1,458,616	0.0199	$ 0.10
57	2078						0.25	1,458,616	0.0171	$ 0.09
Total							43.84		*Average*	$ 0.32
NPV @	6.94%	0.71	0.47	3.91	7 32	1 09	13.50			

Notes:

1. Revenue Requirement rounded to the nearest $10,000.
2. Estimated Maui Electric Sales in MWH. Using 2050 forecasted sales for years thereafter.
3. Maui Electric typical residential energy consumption, per month.

KEY ASSUMPTIONS USED IN FINANCIAL ANALYSIS

The Companies utilized various assumptions in the high level, economic analysis to forecast revenue requirements and bill impacts. This high-level forecast uses broad or simplified assumptions for the purpose of estimating revenue requirements over the life of the investment and a typical monthly residential bill impact. Actual results may differ based on the application of specific rules and on the actual costs incurred. The key assumptions are highlighted 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 TY2020 Rate Case Dkt 2019-0085 Final D&O 37387 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	0.58%	2.50%	0.01%	0.01%	0.016%	0.01%
Long Term Debt (Taxable Debt)	41.42%	4.55%	1.88%	1.40%	2.068%	1.88%
Hybrids	0.00%	0.00%	0.00%	0.00%	0.000%	0.00%
Preferred Stock	0.85%	5.33%	0.05%	0.05%	0.067%	0.06%
Common Stock	57.15%	9.50%	5.43%	5.43%	8.026%	7.31%
	100.00%		7.37%	6.885%	10.177%	9.272%

Figure 2 – Hawai'i Electric Light

HELCO TY2019 Rate Case Dkt 2018-0368 PUC Final D&O 37237 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	0.61%	3.75%	0.02%	0.02%	0.025%	0.02%
Long Term Debt (Taxable Debt)	40.59%	4.79%	1.94%	1.44%	2.134%	1.94%
Hybrids	0.80%	7.83%	0.06%	0.05%	0.069%	0.06%
Preferred Stock	1.17%	8.12%	0.09%	0.09%	0.140%	0.13%
Common Stock	56.83%	9.50%	5.40%	5.40%	7.980%	7.27%
	100.00%		7.52%	7.001%	10.349%	9.429%

Figure 3 – Maui Electric

MECO TY2018 Rate Case Dkt 2017-0150 Final D&O No. 36219 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	1.37%	3.00%	0.04%	0.03%	0.045%	0.04%
Long Term Debt (Taxable Debt)	38.68%	4.54%	1.76%	1.30%	1.928%	1.76%
Hybrids	1.96%	7.16%	0.14%	0.10%	0.154%	0.14%
Preferred Stock	0.98%	8.15%	0.08%	0.08%	0.118%	0.11%
Common Stock	57.02%	9.50%	5.42%	5.42%	8.007%	7.30%
	100.00%		7.43%	6.935%	10.251%	9.341%

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 2020 test year rate case, Maui Electric's 2018 test year rate case, and Hawai'i Electric Light's 2019 test year rate case.

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 – ADMS Consolidated

	Hardware	Deferred Software
Expected Useful Life	5	12
MACRS Tax Life ("Tax Life")	5	-
Tax Class Life ("Class Life")	-	3

Figure 6 – Field Devices Consolidated

	Line Sensors	RFI	SVC	Intelligent Switches
Expected Useful Life	15	15	30	53
MACRS Tax Life ("Tax Life")	20	20	20	20
Tax Class Life ("Class Life")	-	-	-	-

IV. INVESTMENT ASSUMPTIONS

Investment assumptions are based on the forecasts of costs based on the scope of Phase 2. Please refer to figures 7 through 12 below for current assumptions used in the forecast.

Figure 7 – ADMS Hawaiian Electric

Project	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 and beyond	Useful Life
Hardware	[redacted]						5
Deferred Software		[redacted]	[redacted]		[redacted]		12
Pre-Implementation O&M	[redacted]						
Implementation O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Post-Implementation O&M						[redacted]	
TOTAL	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

Figure 8 – ADMS Hawaii Electric Light

Project	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 and beyond	Useful Life
Hardware	[redacted]						5
Deferred Software			[redacted]	[redacted]	[redacted]		12
Pre-Implementation O&M	[redacted]						
Implementation O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Post-Implementation O&M						[redacted]	
TOTAL	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

Figure 9 – ADMS Maui Electric

Project	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 and beyond	Useful Life
Hardware	[redacted]						5
Deferred Software			[redacted]	[redacted]	[redacted]		12
Pre-Implementation O&M	[redacted]						
Implementation O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Post-Implementation O&M						[redacted]	
TOTAL	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

Figure 10 – Field Devices Hawaiian Electric

Project	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 and beyond	Useful Life
Line Sensors	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		15
RFI	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		15
SVC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		30
Intelligent Switches	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		53
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
TOTAL	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

Figure 11 – Field Devices Hawaiʻi Electric Light

Project	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 and beyond	Useful Life
Line Sensors	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		15
RFI	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		15
SVC	[redacted]	[redacted]					30
Intelligent Switches	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		53
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
TOTAL	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

Figure 12 – Field Devices Maui Electric

Project	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 and beyond	Useful Life
Line Sensors	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		15
RFI	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		15
SVC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		30
Intelligent Switches	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		53
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
TOTAL	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

Exhibit I

Grid Modernization Phase 2 ADMS and Field Device Application

Hawaiian Electric Companies' Decoupling Calculation Workbook

The purpose of this Schedule B1 is to illustrate how the Grid Modernization Phase 2 project will flow through the MPIR/EPRM mechanism into Target Revenue. All other numbers are from Transmittal No. 21-02, Notice to Update Target Revenue through the MPIR and Calculation of 2020 PIMS, filed February 25, 2021 and will change
This illustration is based on an assumed recovery of O&M expenses only in 2022

SCHEDULE B1
(To be filed by Feb 2022 for Yr 2)
PAGE 1 OF 1

HAWAIIAN ELECTRIC COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
DETERMINATION OF TARGET REVENUES

Line No	Description (a)	Reference (b)		Docket No 2016-0328 Amounts (c)	Docket No 2016-0328 Amounts (d)	Docket No 2019-0085 Amounts (e)	Docket No 2019-0085 Amounts (f)	Docket No 2019-0085 Amounts (g)	Note (7) MPIR/EPRM Illustration Effective 1/1/2022 (h)
1	Last Rate Case Annual Electric Revenue at Approved Rate Levels	Note (2), (2a), (6a)	$000s	$ 1,529,709	$ 1,529,709	$ 1,529,709	$ 1,529,709	$ 1,531,852	[redacted]
2	Less: Fuel Expense	Note (2)	$000s	$ (327,609)	$ (327,609)	$ (327,609)	$ (327,609)	$ (327,609)	
3	Purchased Power Expense	Note (2)	$000s	$ (466,211)	$ (466,211)	$ (466,211)	$ (466,211)	$ (466,211)	
4	Revenue Taxes on Line 1 (8.885% statutory rates)		$000s	$ (135,915)	$ (135,915)	$ (135,915)	$ (135,915)	$ (136,105)	
5	Last Rate Order Target Annual Revenues	Sum Lines 1-4	$000s	$ 599,974	$ 599,974	$ 599,974	$ 599,974	$ 601,927	
6	Authorized RAM Revenues	Note (3)	$000s	$ -	$ -	$ -	$ -	$ -	$ -
7	Less: Revenue Taxes on Line 6 at 8.885%		$000s	$ -	$ -	$ -	$ -	$ -	$ -
8	Net RAM Adjustment - Test Year +1	Lines 6 + 7	$000s	$ -	$ -	$ -	$ -	$ -	$ -
9	Authorized RAM Revenues	Note (4)	$000s	$ 20,351	$ -	$ -	$ -	$ -	$ -
10	Less: Revenue Taxes on Line 9 at 8.885%		$000s	$ (1,808)	$ -	$ -	$ -	$ -	$ -
11	Net RAM Adjustment - Test Year +2	Lines 9 + 10	$000s	$ 18,543	$ -	$ -	$ -	$ -	$ -
12	Authorized RAM Revenues	Note (5)	$000s	$ -	$ 40,988	$ 40,988	$ 40,988	$ 40,988	[redacted]
13	Less: Revenue Taxes on Line 12 at 8.885%		$000s	$ -	$ (3,642)	$ (3,642)	$ (3,642)	$ (3,642)	
14	Net RAM Adjustment - Test Year +3	Lines 12 + 13	$000s	$ -	$ 37,346	$ 37,346	$ 37,346	$ 37,346	
15	Authorized MPIR/EPRM Revenues	Sch F, Note (5), (6), (7)	$000s	$ 21,924	$ 21,924	$ 22,124	$ 21,532	$ 21,532	
16	Less: Revenue Taxes on Line 15 at 8.885%		$000s	$ (1,948)	$ (1,948)	$ (1,966)	$ (1,913)	$ (1,913)	
17	Net MPIR/EPRM Adjustment	Lines 15 + 16	$000s	$ 19,976	$ 19,976	$ 20,158	$ 19,619	$ 19,619	
18	Less: EARNINGS SHARING REVENUE CREDITS	Note (5)	$000s	$ -	$ -	$ -	$ -	$ -	$ -
19	Less: Revenue Taxes on Line 18 at 8.885%		$000s	$ -	$ -	$ -	$ -	$ -	$ -
20	Net Earnings Sharing Revenue Credits	Lines 18 + 19	$000s	$ -	$ -	$ -	$ -	$ -	$ -
21	Less: PERFORMANCE INCENTIVE MECHANISM	Note (5)	$000s	$ (1,269)	$ 923	$ 923	$ 923	$ 923	[redacted]
22	Less: Revenue Taxes on Line 21 at 8.885%		$000s	$ 113	$ (82)	$ (82)	$ (82)	$ (82)	
23	Net Performance Incentive Mechanism	Lines 21 + 22	$000s	$ (1,157)	$ 841	$ 841	$ 841	$ 841	
24	Less: 2017 TEST YEAR FINAL D&O REFUND	Note (5)	$000s	$ (48)	$ -	$ -	$ -	$ -	$ -
25	Less: Revenue Taxes on Line 24 at 8.885%		$000s	$ 4	$ -	$ -	$ -	$ -	$ -
26	Net 2017 Test Year Final D&O Refund	Lines 24 + 25	$000s	$ (44)	$ -	$ -	$ -	$ -	$ -
27	Less: AFFILIATE TRANSACTION REFUND	Note (5)	$000s	$ -	$ (43)	$ (43)	$ (43)	$ (43)	[redacted]
28	Less: Revenue Taxes on Line 27 at 8.885%		$000s	$ -	$ 4	$ 4	$ 4	$ 4	
29	Net Affiliate Transaction Refund	Lines 27 + 28	$000s	$ -	$ (39)	$ (39)	$ (39)	$ (39)	
30	Add: OBF PROGRAM IMPLEMENTATION COSTS	Note (5)	$000s	$ 844	$ 854	$ 854	$ 854	$ 854	
31	Less: Revenue Taxes on Line 30 at 8.885%		$000s	$ (75)	$ (76)	$ (76)	$ (76)	$ (76)	
32	Net OBF Program Implementation Costs	Lines 30 + 31	$000s	$ 769	$ 779	$ 779	$ 779	$ 779	
33	Less: PUC-ORDERED MAJOR OR BASELINE CAPITAL CREDITS:	Note (5)	$000s	$ -	$ -	$ -	$ -	$ -	$ -
34	Total Annual Target Revenues								
35	June 1, 2019 Annualized Revenues w/ RAM Increase & MPIR accrued 1/1/2020	Col (c), lines (5+11+17 +20+23+26+32+33)	$000s	$ 638,062					
36	June 1, 2020 Annualized Revenues w/ RAM Increase & MPIR accrued 1/1/2020	Col (d), lines (5+14+17 +20+23+26+29+32+33)	$000s		$ 658,877				
37	June 1, 2020 Annualized Revenues w/ RAM Increase & MPIR accrued 11/1/2020	Col (e), lines (5+14+17 +20+23+26+29+32+33)	$000s			$ 659,059			
38	June 1, 2020 Annualized Revenues w/ RAM Increase & MPIR accrued 1/1/2021	Col (f), lines (5+14+17 +20+23+26+29+32+33)	$000s				$ 658,520		
39	June 1, 2020 Annualized Revenues w/ RAM Incr & MPIR accrued 1/1/2021, adjusted for removal of Tax Act Implementation lag eff 4/13/2021	Col (g), lines (5+14+17 +20+23+26+29+32+33)	$000s					$ 660,473	
40	June 1, 2020 Annualized Revenues w/ RAM Incr & MPIR/EPRM accrued 1/1/2022								[redacted]

Line No		Note (1)	Note (1a)	Note (5) 2020	2020	2020	Note (6) 2021	Note (6a) 2021	Note (7) 2022
41	Distribution of Target Revenues by Month:								
42	January	8.19%	8.49%	$ 52,257,254			$55,928,097		[redacted]
43	February	7.59%	7.67%	$ 48,428,884			$50,528,233		
44	March	8.10%	8.49%	$ 51,682,998			$55,928,097		
45	April	7.98%	8.22%	$ 50,917,324			$21,649,501	$32,570,542	
46	May	8.40%	8.49%	$ 53,597,183				$56,093,931	
47	June	8.07%	8.22%		$53,171,386				
48	July	8.70%	8.49%		$57,322,312				
49	August	8.94%	8.49%		$58,903,617				
50	September	8.65%	8.22%		$56,992,873				
51	October	8.84%	8.49%		$58,244,740				
52	November	8.26%	8.22%			$54,438,285			
53	December	8.28%	8.49%			$54,570,097			
54	Total Distributed Target Revenues	100.00%	100.00%	$ 256,883,643	$284,634,928	$109,008,382	$184,033,928	$88,664,473	

Footnotes

1 RBA Tariff Effective February 16, 2018 to reflect 2017 test year.

1a Monthly Allocation Factors based on the number of days in the month as a percentage of the number of days in the year, with the allocation factor for February set such that the total of the monthly allocation factors sums to 100%. Effective January 2021.

2 Test Year 2017 2nd Interim Increase provided for in Order No. 35335, issued March 9, 2018 in Docket No. 2016-0328 -$603 $000s

2a Reduction for Tax Act Implementation Lag (March 2018 Settlement Tariff Sheets, Attachment 3, filed March 16, 2018, in accordance with Order No. 35335) -$2,143 $000s

3 Transmittal 18-01 filed May 29, 2018, establishing 2018 target revenue effective June 1, 2018.

4 Transmittal Nos. 19-01, 19-02, 19-03 Consolidated (Decoupling) - 2019 RBA Rate Adjustment, filed May 28, 2019, establishing 2019 target revenue effective June 1, 2019.

5 Test Year 2020 Proposed Final Tariffs, including Target Revenue Workpapers effective January 1, 2020 (Exhibit 3) and November 1, 2020 (Exhibit 3A), filed November 6, 2020 and approved in Order No. 37486 in Docket No. 2019-0085 on December 11, 2020.

6 MPIR Revenue accrual effective January 1, 2021 filed in Transmittal 21-02 on February 25, 2021, until such costs are reflected in base rates

6a Pursuant to Final Decision & Order No 37387 filed October 22, 2020 in Docket No 2019-0085, there is a zero increase in base rates from the 2017 Test Year. In Hawaiian Electric's 2017 Test Year March 2018 Settlement Tariff Sheets (in Footnote 2a above) Target Revenue incorporated a reduction for the Tax Act Implementation Lag ($2,143,224). The Company amortized the Tax Act Impementation Lag over 3 years, beginning April 13, 2018 through April 12, 2021, therefore Target Revenue is being adjusted effective April 13, 2021. See Transmittal No 21-01, filed January 29,

Note: The amounts for the Grid Mod Phase 2 Project included in this illustration have been rounded to $100 thousands. Actual amounts will be used in the actual filing.

HAWAIIAN ELECTRIC COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
MAJOR PROJECT INTERIM RECOVERY &
EXCEPTIONAL PROJECT RECOVERY MECHANISM

The purpose of this Illustration is to reflect the inclusion of the Grid Moderization Phase 2 Project in the year following project in service as part of the February 2022 annual MPIR/EPRM true-up filing which will also include an update for all MPIR/EPRM project costs recorded as of December 31, 2021 and 2022 activity.
This illustration is based on an assumed recovery of O&M expenses only in 2022.

Line No.	Description	Reference	Amount $000
	(a)	(b)	(c)
1	Schofield Generating Station	Note 1	[redacted]
2	Docket No. 2017-0213		
3	West Loch PV Project		[redacted]
4	Docket No. 2016-0342		
5	Grid Mod Phase 1 Project		[redacted]
6	Docket No. 2018-0141		
7	Grid Mod Phase 2 Project	Schedule F4	[redacted]
8	Docket No. 2019-0327		
9	Total MPIR/EPRM Recovery		[redacted]
10	Revenue Tax Factor (1/(1-8.885%))		[redacted]
11	**MPIR/EPRM Total**		[redacted]
			To Sch B1

The purpose of this illustration is to reflect the calculation of EPRM recovery in the year following project in service
filed as part of the annual MPIR/EPRM true-up filing to be filed no later than February 2022
EPRM to be in effect until such costs are reflected in base rates
This illustration is based on an assumed recovery of O&M expenses only in 2022

Note: The amounts have been rounded to the $100 thousands for purposes of this illustration Actual amounts will be used for the

HAWAIIAN ELECTRIC COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF EPRM RECOVERY
ILLUSTRATIVE EPRM PROJECT - GRID MODERNIZATION PHASE 2
$ in thousands

To the extent that recovery via the test year varies from actual costs incurred, a EPRM true-up adjustment will be made in the subsequent annual MPIR/EPRM true-up filing

Line No	Description	Reference	Recorded at 12/31/2021	2022 Activity	Ending Balance as of 12/31/22	Average Balance	EPRM
	(a)	(b)	(c)	(d)	(e)	(f) = ((c)+(e))/2	(g)
	Return on Investment - Grid Mod Phase 2						
1	Plant in Service (not to exceed PUC approved amount)	As applicable	-	-	-	-	
2	Accum Depreciation	As applicable	-	-	-	-	
3	Net Cost of Plant in Service		-	-	-	-	
4	ADIT	As applicable	-	-	-	-	
5	State ITC	As applicable	-	-	-	-	
6	Total Deductions		-	-	-	-	
7	Total Rate Base		$ -	$ -	$ -	-	
8	Average Rate Base					$ -	
9	Rate of Return (grossed-up for income taxes, before rev taxes)	*Schedule F4, pg 2*		Will be revised to reflect the most recent PUC approved rate of return		9 27%	
10	Annualized Return on Investment (before revenue taxes)						$ -
11	Depreciation Expense (Note 1)	Not Applicable				-	
12	Operating & Maintenance Expense	Note 2				[redacted]	
12a	Prior year reconciliation of O&M to actuals	Note 2				-	
12b	Pre-Implementation O&M Expense	Note 3				[redacted]	
13	Amortization of State ITC	Not Applicable				-	
14	Lease Rent Expense	Not Applicable				-	
15	Other Expense	Not Applicable				-	
16	Total Expenses						[redacted]
17	Exceptional Project Recovery Mechanism Total						[redacted]
							To Sch F

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 depreciation expense at existing, approved depreciation accrual rates at the time of filing

Note 2: Requesting recovery of the estimated incremental implementation O&M costs for data base conversion, including data gathering and customer to transformer mapping for the OMS module of the ADMS to be incurred in 2022 Estimated 2022 O&M expenses will be reconciled to actual O&M expense in the 2023 annual MPIR/EPRM filing via Line 12a See Exhibit D - Interim Recovery of the Application

SCHEDULE F1
(To be filed by Feb 2022 for Yr 2)
PAGE 2 OF 2

Hawaiian Electric Company, Inc.

Revenues at Current Effective Rates
COMPOSITE EMBEDDED COST OF CAPITAL
Estimated 2020 Average

This schedule/workpaper has been filed in Transmittal No. 21-02, Notice Transmittal to Update Target Revenue through the Major Project Interim Recovery Adjustment Mechanism and Calculation of 2020 Performance Incentive Mechanism Financial Incentives, Attachment 1. filed February 25. 2021.

In Decision & Order No. 37387 issued on October 22, 2020 in Docket No. 2019-0085, the Commission approved the Settlement Letter, whereby the Parties agreed on the weights and earnings requirements for short-term debt, long-term debt, and preferred stock, and that Hawaiian Electric's ROE and equity ratio for Hawaiian Electric should mirror HELCO's 2019 test year rate case.
The Settlement Agreement rate of return applied an ROE of 9.50% and total equity ratio of 58.00% based on Final Decision and Order No. 37237 issued on July 28, 2020, in Docket No. 2018-0368).

	A	B	C	D	E	F
	Capitalization					
	Amount in Thousands	Percent of Total	Earnings Reqmts	Weighted Earnings Reqmts (B) x (C)	INCOME TAX FACTOR (Note 1)	PRETAX WEIGHTED EARNINGS REQMTS
Short-Term Debt	14,690	0.58	2.50%	0.01%	1.0000	0.0100%
Long-Term Debt	1,044,127	41.42	4.55%	1.88%	1.0000	1.8800%
Preferred Stock	21,302	0.85	5.33%	0.05%	1.3468	0.0673%
Common Equity	1,440,676	57.15	9.50%	5.43%	1.3468	7.3133%
Total	2,520,795	100.00				
Estimated Composite Cost of Capital				7.37%		9.27%
						1.0975
Estimated Pretax Composite Cost of Capital						10.175%

Source: Docket No. 2019-0085 - Hawaiian Electric 2020 Test Year Rate Case Final Tariffs, Exhibit 2, filed November 6, 2020

Note 1:	Composite Federal & State Income Tax Rate	25.75%
	Income Tax Factor (1 / 1-tax rate)	1.3468354

The purpose of this Schedule B1 is to illustrate how the Grid Modernization Phase 2 project will flow through the MPIR/EPRM mechanism into Target Revenue. All other numbers are from Transmittal No. 21-03, Notice to Update Target Revenue through the MPIR and Calculation of 2020 PIMS, filed February 25, 2021 and will change. This illustration is based on an assumed recovery of O&M expenses only in 2022.

SCHEDULE B1
(To be filed by Feb 2022 for Yr 2)
PAGE 1 OF 1

HAWAII ELECTRIC LIGHT COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
DETERMINATION OF TARGET REVENUES

Line No	Description (a)	Reference (b)		Interim D&O No 36761 Docket No 2018-0368 Amounts (c)	Interim D&O No 36761 Docket No 2018-0368 Amounts (d)	Interim D&O No 36761 Docket No 2018-0368 Amounts (e)	Note 6 MPIR/EPRM Illustration Effective 1/1/2022 (e)
1	Last Rate Case Annual Electric Revenue at Approved Rate Levels	Note 1	$000s	$ 169,045	$ 169,045	$ 169,045	$ [redacted]
2	Less: Fuel Expense	Note 1	$000s	$ -	$ -	$ -	$ -
3	Purchased Power Expense	Note 1	$000s	$ -	$ -	$ -	$ -
4	Revenue Taxes on Line 1 (8 885% statutory rates)		$000s	$ (15,020)	$ (15,020)	$ (15,020)	$ [redacted]
5	Last Rate Order Target Annual Revenues	Sum Lines 1 thru 4	$000s	$ 154,025	$ 154,025	$ 154,025	$ [redacted]
6	Add: Authorized RAM Revenues - Transmittal No 18-02	Note 2	$000s	$ -	$ -	$ -	$ -
7	Less: Revenue Taxes on Line 6 at 8 885%		$000s	$ -	$ -	$ -	$ -
8	Net RAM Adjustment - Test Year +2	Line 6 + 7	$000s	$ -	$ -	$ -	$ -
9	Authorized RAM Revenues - Transmittal No 19-02	Note 2a	$000s	$ -	$ -	$ -	$ -
10	Less: Revenue Taxes on Line 9 at 8 885%		$000s	$ -	$ -	$ -	$ -
11	Net RAM Adjustment - Test Year +3	Line 9 + 10	$000s	$ -	$ -	$ -	$ -
12	Authorized RAM Revenues	Note 3	$000s	$ -	$ 3,212	$ 3,212	$ [redacted]
13	Less: Revenue Taxes on Line 12 at 8 885%		$000s	$ -	$ (285)	$ (285)	$ [redacted]
14	Net RAM Adjustment - Test Year +1	Line 12 + 13	$000s	$ -	$ 2,926	$ 2,926	$ [redacted]
15	Authorized MPIR/EPRM Revenues	Schedule F; Note 3, 5, 6	$000s	$ 62	$ 62	$ 127	$ [redacted]
16	Less: Revenue Taxes on Line 15 at 8 885%		$000s	$ (6)	$ (6)	$ (11)	$ [redacted]
17	Net MPIR/EPRM Adjustment	Line 15 + 16	$000s	$ 57	$ 57	$ 116	$ [redacted]
18	Less: EARNINGS SHARING REVENUE CREDITS	Note 3	$000s	$ -	$ -	$ -	$ -
19	Less: Revenue Taxes on Line 18 at 8 885%		$000s	$ -	$ -	$ -	$ -
20	Net Earnings Sharing Revenue Credits	Line 18 + 19	$000s	$ -	$ -	$ -	$ -
21	Less: PERFORMANCE INCENTIVE MECHANISM REWARD (PENALTY)	Note 3	$000s	$ (15)	$ (156)	$ (156)	$ [redacted]
22	Less: Revenue Taxes on Line 21 at 8 885%		$000s	$ 1	$ 14	$ 14	$ [redacted]
23	Net Performance Incentive Mechanism	Lines 21 + 22	$000s	$ (14)	$ (142)	$ (142)	$ [redacted]
24	Less: 2016 TEST YEAR FINAL D&O REFUND	Note 3	$000s	$ (74)	$ -	$ -	$ -
25	Less: Revenue Taxes on Line 24 at 8 885%		$000s	$ 7	$ -	$ -	$ -
26	Net 2016 Test Year Final D&O Refund	Lines 24 + 25	$000s	$ (67)	$ -	$ -	$ -
27	Add: OBF PROGRAM IMPLEMENTATION COSTS	Note 3	$000s	$ 237	$ 239	$ 239	$ [redacted]
28	Less: Revenue Taxes on Line 27 at 8 885%		$000s	$ (21)	$ (21)	$ (21)	$ [redacted]
29	Net OBF Program Implementation Costs	Lines 27 + 28	$000s	$ 216	$ 218	$ 218	$ [redacted]
30	PUC-ORDERED MAJOR OR BASELINE CAPITAL CREDITS:	Note 3	$000s	$ -	$ -	$ -	$ -
31	Total Annual Target Revenues						
32	June 1, 2018 Annualized Revenues + RAM Increase	Lines (5+8)	$000s				
33	June 1, 2019 Annualized Revenues + RAM Increase	Lines (5+11+17+23+26+29+30)	$000s				
34	June 1, 2019 Annualized Revenues + RAM Increase, adjusted for removal of Tax Act Implementation lag effective Nov 1, 2019	Lines (5+11+17+20+23+26+29+30)	$000s				
35	Interim D&O, dated November 13, 2019 Annualized Revenues w/ Zero Interim Increase & MPIR accrued 1/1/2020	Lines (5+17+20+23+26+29+30)	$000s	$ 154,217			
36	Interim D&O, dated November 13, 2019 Annualized Revenues w/ Zero Interim Increase + RAM & MPIR accrued 1/1/2020	Lines (5+14+17+20+23+26+29+30)	$000s		$ 157,084		
37	Interim D&O, dated November 13, 2019 Annualized Revenues w/ Zero Interim Increase + RAM + MPIR accrued 1/1/2021	Lines (5+14+17+20+23+26+29+30)	$000s			$ 157,143	
38	June 1, 2020 Annualized Revenues w/ RAM Incr & MPIR/EPRM accrued 1/1/2022						$ [redacted]
39	Monthly Allocation Factors for the Target Revenue	Note 4		2020	2020	Note 5 2021	Note 6 2022
40	January	8 493%		$ 13,097,623		$ 13,346,155	$ [redacted]
41	February	7 673%		$ 11,833,046		$ 12,057,582	$ [redacted]
42	March	8 493%		$ 13,097,623		$ 13,346,155	$ [redacted]
43	April	8 219%		$ 12,675,069		$ 12,915,583	$ [redacted]
44	May	8 493%		$ 13,097,623		$ 13,346,155	$ [redacted]
45	June	8 219%			$ 12,910,734		$ [redacted]
46	July	8 493%			$ 13,341,144		$ [redacted]
47	August	8 493%			$ 13,341,144		$ [redacted]
48	September	8 219%			$ 12,910,734		$ [redacted]
49	October	8 493%			$ 13,341,144		$ [redacted]
50	November	8 219%			$ 12,910,734		$ [redacted]
51	December	8 493%			$ 13,341,144		$ [redacted]
52	Total	100 00%		$ 63,800,984	$ 92,096,778	$ 65,011,630	$ [redacted]

Note: Amounts may not foot due to rounding

Note 1: Col c, d, e: Interim Decision and Order No 36761, filed on November 13, 2019, in Docket No 2018-0368 ("Hawai'i Electric Light 2019 Interim D&O") approving HELCO Statement of

Note 2: Transmittal 18-02 filed May 29, 2018, establishing 2018 target revenue effective June 1, 2018

Note 2a Transmittal 19-02 filed May 28, 2019, establishing 2019 target revenue effective June 1, 2019

Note 3: Per Transmittal 20-02 - Consolidated (Decoupling) - 2020 RBA Rate Adjustment, Attachment 2, Hawaii Electric Light, Schedule B1, filed June 5, 2020

Note 4: Per Transmittal 20-02 - Consolidated (Decoupling) - 2020 RBA Rate Adjustment, Attachment 2, Hawaii Electric Light, Schedule B1, filed June 5, 2020 and effective January 1, 2020
Monthly Allocation Factors are based on the number of days in the month as a percentage of the number of days in the year, with the allocation factor for February set such that the total of

Note 5: MPIR Revenue accrual effective January 1, 2021 filed in Transmittal 21-03 on February 25, 2021, until such costs are reflected in base rates

Note 6: FOR ILLUSTRATION PURPOSES ONLY - MPIR/EPRM Revenue accrual starting January 1, 2022 filed in Transmittal xx-xx, filed Month Day, Year

Note: The amounts for the Grid Mod Phase 2 Project included in this illustration have been rounded to $100 thousands. Actual amounts will be used in the actual filing.

SCHEDULE F
(To be filed by Feb 2022
PAGE 1 OF 1

HAWAII ELECTRIC LIGHT COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
MAJOR PROJECT INTERIM RECOVERY &
EXCEPTIONAL PROJECT RECOVERY MECHANISM

The purpose of this Illustration is to reflect the inclusion of the Grid Moderization Phase 2 Pro
year following project in service as part of the February 2022 annual MPIR/EPRM true-up fil
will also include an update for all MPIR/EPRM project costs recorded as of December 31, 202
activity.
This illustration is based on an assumed recovery of O&M expenses only in 2022.

Line No.	Description	Reference
	(a)	(b)
1	Grid Mod Phase 1 Project	Note 1
2	Docket No. 2018-0141	
3	Grid Mod Phase 2 Project	Schedule F4
4	Docket No. 2019-0327	
5	Total MPIR/EPRM Recovery	
6	Revenue Tax Factor (1/(1-8.885%))	
7	**MPIR/EPRM Total**	

Note 1: Transmittal No. 21-03, Notice to Update Target Revenue through the MPIR and Calcu
2020 PIMS, filed February 25, 2021.

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ling which
!1 and 2022

Amount $000
(c)
$ [redacted]
[redacted]
[redacted]
[redacted]
$ [redacted]
To Sch B1

lation of

The [illegible] of EPRM recovery in the year following project in service filed as part of the annual MPIR/EPRM true-up filing to be filed no later than February 2022
EPRM to be in effect until such costs are reflected in base rates
This illustration is based on an assumed recovery of O&M expenses only in 2022

Note: The amounts have been rounded to the $100 thousands for purposes of this illustration Actual amounts will be used for the

HAWAII ELECTRIC LIGHT COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF EPRM RECOVERY
ILLUSTRATIVE EPRM PROJECT - GRID MODERNIZATION PHASE 2
$ in thousands

To the extent that recovery via the test year varies from actual costs incurred, a EPRM true-up adjustment will be made in the subsequent annual MPIR/EPRM true-up filing

Line No	Description	Reference	Recorded at 12/31/2021	2022 Activity	Ending Balance as of 12/31/22	Average Balance	EPRM
	(a)	(b)	(c)	(d)	(e)	(f) = ((c)+(e))/2	(g)
	Return on Investment - Grid Mod Phase 2						
1	Plant in Service (not to exceed PUC approved amount)	As applicable	-	-	-	-	
2	Accum Depreciation	As applicable	-	-	-	-	
3	Net Cost of Plant in Service		-	-	-	-	
4	ADIT	As applicable	-	-	-	-	
5	State ITC	As applicable	-	-	-	-	
6	Total Deductions		-	-	-	-	
7	Total Rate Base		$ -	$ -	$ -	-	
8	Average Rate Base					$ -	
9	Rate of Return (grossed-up for income taxes, before rev taxes)	Note 4		Will be revised to reflect the most recent PUC approved rate of return		9 43%	
10	Annualized Return on Investment (before revenue taxes)						$ -
11	Depreciation Expense (Note 1)	Not Applicable				-	
12	Operating & Maintenance Expense	Note 2				[redacted]	
12a	Prior year reconciliation of O&M to actuals	Note 2				-	
12b	Pre-Implementation O&M Expense	Note 3				[redacted]	
13	Amortization of State ITC	Not Applicable				-	
14	Lease Rent Expense	Not Applicable				-	
15	Other Expense	Not Applicable				-	
16	Total Expenses						$ [redacted]
17	Exceptional Project Recovery Mechanism Total						$ [redacted]
							[redacted]

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 depreciation expense at existing, approved depreciation accrual rates at the time of filing

Note 2: Requesting recovery of the estimated incremental implementation O&M costs for data base conversion, including data gathering and customer to transformer mapping for the OMS module of the ADMS to be incurred in 2022 Estimated 2022 O&M expenses will be reconciled to actual O&M expense in the 2023 annual MPIR/EPRM filing via Line 12a See Exhibit D - Interim Recovery of the Application

Note 3: Requesting recovery of pre-implementation O&M expenses for outside services to conduct Job Task Analysis and Job Role Impact Analysis to identify risk and change factors and gaps so that the companies can then develop the necessary competence training and curriculum for using the ADMS Job Positions may also be redefined See Exhibit D - Interim Recovery of the Application

Note 4: Transmittal Nos 20-01, 20-02, 20-03 Consolidated (Decoupling) - 2020 RBA Rate Adjustment Tariff Filings - Final Revised 2020 RBA Rate Adjustment Tariff Filing, HELCO-WP-L1-003, filed June 5, 2020

The purpose of this Schedule B1 is to illustrate how the Grid Modernization Phase 2 project will flow through the MPIR/EPRM mechanism into Target Revenue All other numbers are from Transmittal No 21-04, Notice to Update Target Revenue through the MPIR and Calculation of 2020 PIMS, filed February 25, 2021 and will change
This illustration is based on an assumed recovery of O&M expenses only in 2022

SCHEDULE B1
(To be filed by Feb 2022 for Yr 2)
PAGE 1 OF 1

MAUI ELECTRIC COMPANY, LIMITED
DECOUPLING CALCULATION WORKBOOK
DETERMINATION OF TARGET REVENUES

Line No	Description (a)	Reference (b)		Docket No 2017-0150 Amounts (c)	Docket No 2017-0150 Amounts (d)	Docket No 2017-0150 Amounts (e)	Note 5 MPIR/EPRM Illustration Effective 1/1/2022 (e)
1	Last Rate Case Annual Electric Revenue at Approved Rate Levels	Note 1	$000s	$ 335,763	$ 335,763	$ 335,763	$ [redacted]
2	Less: Fuel Expense	Note 1	$000s	$ (103,385)	$ (103,385)	$ (103,385)	$ [redacted]
3	Purchased Power Expense	Note 1	$000s	$ (54,970)	$ (54,970)	$ (54,970)	$
4	Revenue Taxes on Line 1 (8 885% statutory rates)		$000s	$ (29,833)	$ (29,833)	$ (29,833)	$
5	Last Rate Order Target Annual Revenues	Sum Lines 1 thru 4	$000s	$ 147,575	$ 147,575	$ 147,575	$ [redacted]
6	Authorized RAM Revenues - Transmittal No 19-03	Note 3	$000s	$ 2,694	$ -	$ -	$ -
7	Less: Revenue Taxes on Line 6 at 8 885%		$000s	$ (239)	$ -	$ -	$ -
8	Net RAM Adjustment - Test Year	Lines 6 + 7	$000s	$ 2,455	$ -	$ -	$ -
9	Authorized RAM Revenues - Transmittal No 20-03	Note 3	$000s	$ -	$ 8,411	$ 8,411	$ [redacted]
10	Less: Revenue Taxes on Line 9 at 8 885%		$000s	$ -	$ (747)	$ (747)	$
11	Net RAM Adjustment - Test Year	Lines 9 + 10	$000s	$ -	$ 7,664	$ 7,664	$
12	Authorized MPIR/EPRM Revenues	Schedule F, Note 3, 4, 5	$000s	$ 57	$ 57	$ 140	$ [redacted]
13	Less: Revenue Taxes on Line 12 at 8 885%		$000s	$ (5)	$ (5)	$ (12)	$
14	Net MPIR/EPRM Adjustment	Lines 12 + 13	$000s	$ 52	$ 52	$ 127	$
15	Less: EARNINGS SHARING REVENUE CREDITS:	Note 3	$000s	$ -	$ -	$ -	$ -
16	Less: Revenue Taxes on Line 15 at 8 885%		$000s	$ -	$ -	$ -	$ -
17	Net Earnings Sharing Revenue Credits	Lines 15 + 16	$000s	$ -	$ -	$ -	$ -
18	Less: PERFORMANCE INCENTIVE MECHANISM REWARD (PENALTY)	Note 3	$000s	$ (395)	$ (501)	$ (501)	$ [redacted]
19	Less: Revenue Taxes on Line 18 at 8 885%		$000s	$ 35	$ 45	$ 45	$
20	Net Performance Incentive Mechanism	Lines 18 + 19	$000s	$ (360)	$ (456)	$ (456)	$
21	Add: OBF Program Implementation Costs:	Note 3	$000s	$ 198	$ 203	$ 203	$ [redacted]
22	Less: Revenue Taxes on Line 24 at 8 885%		$000s	$ (18)	$ (18)	$ (18)	$
23	Net OBF Program Implementation Costs	Lines 21 + 22	$000s	$ 181	$ 185	$ 185	$
24	Less: PUC-ORDERED MAJOR OR BASELINE CAPITAL CREDITS:	Note 3	$000s	$ (10)	$ (141)	$ (141)	$ [redacted]
25	Less: Revenue Taxes on Line 27 at 8 885%		$000s	$ 1	$ 12	$ 12	$
26	Net PUC-Ordered Major or Baseline Capital Credits	Lines 24 + 25	$000s	$ (9)	$ (128)	$ (128)	$
27	Total Annual Target Revenues						
28	June 1, 2019 Annualized Revenues + 2019 RAM Revenues	Lines 5 + 8 + 14 + 17 + 20 + 23 + 26	$000s	$ 149,894			
29	June 1, 2020 Annualized Revenues + 2020 RAM Revenues	Lines 5 + 11 + 14 + 17 + 20 + 23 + 26	$000s		$ 154,892		
30	June 1, 2020 Annualized Revenues + 2020 RAM Revenues + MPIR accrued 01/01/2021	Lines 5 + 11 + 14 + 17 + 20 + 23 + 26	$000s			$ 154,967	
31	June 1, 2020 Annualized Revenues w/ RAM Incr & MPIR/EPRM accrued 1/1/2022						$ [redacted]

Line No	Description	Reference	2020	2020	Note 4 2021	Note 5 [redacted]
32	Distribution of Target Revenues by Month in Dollars:	Note 2				
33	January	8.38%	$ 12,561,126		$ 12,986,206	$ [redacted]
34	February	7.50%	$ 11,242,058		$ 11,622,499	$
35	March	8.06%	$ 12,081,465		$ 12,490,313	$
36	April	7.85%	$ 11,766,687		$ 12,164,883	$
37	May	8.18%	$ 12,261,338		$ 12,676,273	$
38	June	8.19%		$ 12,685,624		$
39	July	8.77%		$ 13,583,996		$
40	August	9.00%		$ 13,940,246		$
41	September	8.50%		$ 13,165,788		$
42	October	8.73%		$ 13,522,039		$
43	November	8.30%		$ 12,856,005		$
44	December	8.54%		$ 13,227,745		$
45	Total Distributed Target Revenues	100.00%	$ 59,912,674	$ 92,981,443	$ 61,940,174	$

Note 1: Column (c)-(e): Parties' Joint Proposed Revsied Schedules and Refund Plan, April 17, 2019, Docket No 2017-0150 Exhibit 1C, page 1 of 48

Note 2: RBA Tariff effective August 23, 2018 based on 2018 test year Maui Electric Interim Increase Tariff Sheets, Docket No 2017-0150, filed August 21, 2018

Note 3: Transmittal Nos 20-01, 20-02, 20-03 Consolidated (Decoupling) - 2020 RBA Rate Adjustment Tariff Filings - Final Revised 2020 RBA Rate Adjustment Traiff Filing, filed on June 5, 2020

Note 4: MPIR Revenue accrual effective January 1, 2021 filed in Transmittal 21-04 on February 25, 2021, until such costs are reflected in base rates

Note 5: FOR ILLUSTRATION PURPOSES ONLY - MPIR/EPRM Revenue accrual starting January 1, 2022 filed in Transmittal xx-xx, filed Month Day, Year

Note: The amounts for the Grid Mod Phase 2 Project included in this illustration have been rounded to $100 thousands. Actual amounts will be used in the actual filing.

SCHEDULE F
(To be filed by Feb 2022 for Yr 2)
PAGE 1 OF 1

MAUI ELECTRIC COMPANY, LIMITED
DECOUPLING CALCULATION WORKBOOK
MAJOR PROJECT INTERIM RECOVERY
EXCEPTIONAL PROJECT RECOVERY MECHANISM

The purpose of this Illustration is to reflect the inclusion of the Grid Moderization Phase 2 Project in the year following project in service as part of the February 2022 annual MPIR/EPRM true-up filing which will also include an update for all MPIR/EPRM project costs recorded as of December 31, 2021 and 2022 activity.
This illustration is based on an assumed recovery of O&M expenses only in 2022.

Line No.	Description	Reference	Amount $000
	(a)	(b)	(c)
1	Grid Mod Phase 1 Project	Note 1	$ [redacted]
2	Docket No. 2018-0141		
3	Grid Mod Phase 2 Project	Schedule F4	[redacted]
4	Docket No. 2019-0327		
5	Total MPIR/EPRM Recovery		[redacted]
6	Revenue Tax Factor (1/(1-8.885%))		1.0975
7	**MPIR/EPRM Total**		$ [redacted]
			To Sch B1

Note 1: Transmittal No. 21-04, Notice to Update Target Revenue through the MPIR and Calculation of 2020 PIMS, filed February 25, 2021.

The purpose of this illustration is to reflect the calculation of EPRM recovery in the year following project in service
filed as part of the annual MPIR/EPRM true-up filing to be filed no later than February 2022
EPRM to be in effect until such costs are reflected in base rates
This illustration is based on an assumed recovery of O&M expenses only in 2022

Note: The amounts have been rounded to the $100 thousands for purposes of this illustration Actual amounts will be used for the

MAUI ELECTRIC COMPANY, LTD.
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF EPRM RECOVERY
ILLUSTRATIVE EPRM PROJECT - GRID MODERNIZATION PHASE 2
$ in thousands

To the extent that recovery via the test year varies from actual costs incurred, a EPRM true-up adjustment will be made in the subsequent annual MPIR/EPRM true-up filing

Line No	Description	Reference	Recorded at 12/31/2021	2022 Activity	Ending Balance as of 12/31/22	Average Balance	EPRM
	(a)	(b)	(c)	(d)	(e)	(f) = ((c)+(e))/2	(g)
	Return on Investment - Grid Mod Phase 2						
1	Plant in Service (not to exceed PUC approved amount)	As applicable	-	-	-	-	
2	Accum Depreciation	As applicable	-	-	-	-	
3	Net Cost of Plant in Service		-	-	-	-	
4	ADIT	As applicable	-	-	-	-	
5	State ITC	As applicable	-	-	-	-	
6	Total Deductions		-	-	-	-	
7	Total Rate Base		$ -	$ -	$ -	-	
8	Average Rate Base					$ -	
9	Rate of Return (grossed-up for income taxes, before rev taxes)	Note 4		Will be revised to reflect the most recent PUC approved rate of return		9 34%	
10	Annualized Return on Investment (before revenue taxes)						$ -
11	Depreciation Expense (Note 1)	Not Applicable				-	
12	Operating & Maintenance Expense	Note 2				[redacted]	
12a	Prior year reconciliation of O&M to actuals	Note 2				-	
12b	Pre-Implementation O&M Expense	Note 3				[redacted]	
13	Amortization of State ITC	Not Applicable				-	
14	Lease Rent Expense	Not Applicable				-	
15	Other Expense	Not Applicable				-	
16	Total Expenses						$ [redacted]
17	Exceptional Project Recovery Mechanism Total						$ [redacted]

[redacted]

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 depreciation expense at existing, approved depreciation accrual rates at the time of filing

Note 2: Requesting recovery of the estimated incremental implementation O&M costs for data base conversion, including data gathering and customer to transformer mapping for the OMS module of the ADMS to be incurred in 2022 Estimated 2022 O&M expenses will be reconciled to actual O&M expense in the 2023 annual MPIR/EPRM filing via Line 12a See Exhibit D - Interim Recovery of the Application

Note 3: Requesting recovery of pre-implementation O&M expenses for outside services to conduct Job Task Analysis and Job Role Impact Analysis to identify risk and change factors and gaps so that the companies can then develop the necessary competence training and curriculum for using the ADMS Job Positions may also be redefined See Exhibit D - Interim Recovery of the Application

Note 4: Transmittal Nos 20-01, 20-02, 20-03 Consolidated (Decoupling) - 2020 RBA Rate Adjustment Tariff Filings - Final Revised 2020 RBA Rate Adjustment Tariff Filing, HELCO-WP-L1-003, filed June 5, 2020

Exhibit J

Grid Modernization Strategy Phase 2 ADMS and Field Device 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 26, 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); outage management system (OMS), Switching Order Management (SOM), Distribution Power Flow (DPF), Distribution State Estimation (DSE), 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.

Allowance for Funds Used During Construction (AFUDC)

Represents the cost of financing regulated construction projects and is capitalized to the cost of property, plant and equipment, where permitted by the regulator.

American National Standard Institute (ANSI)

A private, non-profit organization that administers and coordinates the U.S. voluntary standards and conformity assessment system.

C

Circuit Protection

Devices and processes designed to isolate and "protect" against dangerous overvoltage and fault conditions. Circuit protection on the Companies' grids is complicated by the need for customer-sited generation. Circuit-level events could impact the broader performance of the island system without appropriate measures. Further complicating this, inverter-based generation (such as that produced by photovoltaic solar cells) does not provide the same power characteristics as traditional generation, which can fool traditional protection devices into thinking that dangerous conditions exist.

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 Average Interruption Duration Index (CAIDI)

Measure of outage duration for customers who experience an outage

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.

Customer Service Representative (CSR)

A company representative that interacts with the customer on various subjects related to the services of the company.

D

Damage Management

A module that assists field personnel who collect information on the location and types of damage observed in the field. The collected information is used in the ADMS to assist in making better assignments of crews, determining the equipment that is required for repair and also make better estimates of restoration times. Sometimes also called Damage Assessment.

Decentralized Energy Management System (DEMS)

The DEMS is the name of the product that was approved in the Demand Response Management System ("DRMS") docket. For more information, see Docket No. 2015-0411, Decision and Order No. 34884, issued on October 18, 2017.

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.

Distribution Automation (DA)

An intelligent distribution system that uses a network of sensors, controls, switches, and communication devices to perform distribution system functions.

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.

Distribution Management System (DMS)

A DMS monitors & controls the distribution network and acts as a decision support system to assist the grid operators with the monitoring and control of the distribution 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.

Distribution Operator's Training Simulator (DOTS)

A module that simulates the behavior of the distribution system and other external inputs to an ADMS that mimics real responses to user's actions to assist in the training of distribution operators. Simulated scenarios can include faults, planned outages, and storms.

Distribution System Planning and applications (DSPx)

Set of Department of Energy (DOE) documents covering modern distribution system planning.

Distribution State Estimation (DSE)

A module of an ADMS that provides estimation of the entire voltage and power flow state of distribution system using real-time measurements from SCADA and pseudo-measurements such as estimated load and distribution generation.

E

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.

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.

Energy Management System (EMS)

A System Operations tool to monitor and manage the electrical transmission system.

Estimated Restoration Time (ERT)

An estimate of the time until an outage is restored based upon known conditions, including time of day, number of crews on duty, outage prioritization rules, and size of outages. ERTs are calculated by an ADMS and are provided as a customer service. Outage management functions of an ADMS help maintain individual and global estimates of restoration times. Also sometimes called Estimated Restoration Time (ERT).

Exceptional Project Recovery Mechanism (EPRM)

A method of recovering capital and deferred project-related costs that align with Commission-issued EPRM Guidelines regarding cost recovery through the designated EPRM adjustment mechanism, as set forth in Order No. 37507, issued on December 23, 2020, in Docket No. 2018-0088.

F

Fault Location Analysis (FLA)

A module of an ADMS that uses measurements of fault current and a circuit impedance model to identify the distance from the source and thus one or more probable location(s) of a fault.

Fault Location, Isolation, and Service Restoration (FLISR)

Includes the automatic sectionalizing, restoration, and reconfiguration of circuits. This module coordinates operation of field devices to automatically determine the location of a fault and rapidly reconfigure the flow of electricity so that some or all customers can avoid experiencing sustained 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

Geospatial Information System (GIS)

A system used to capture, manage and display data in a geographical format.

Generally Accepted Accounting Principles ("GAAP")

A common set of accounting principles, standards, and procedures issued by the Financial Accounting Standards Board (FASB).

Grid Edge

"Grid edge" refers to the seam where the distribution system meets the customer premise. It is a broad term intended to capture the Companies' most distributed assets and customer resources.

Greenhouse Gases (GHG)

Gases that absorb radiant energy within the thermal infrared range, e.g., carbon dioxide, methane, and chlorofluorocarbons.

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 on August 29, 2017.

H

Hawaiian Electric Companies (the Companies)

Hawaiian Electric Company, Inc. (Hawaiian Electric), Hawaiʻi Electric Light Company, Inc. (Hawaiʻi Electric Light), and Maui Electric Company, Limited (Maui Electric), are collectively referred to herein as "Hawaiian Electric Companies" or "the Companies."

Hosting Capacity (HC)

Hosting Capacity is an estimate of the amount of private rooftop solar that may be accommodated on a distribution circuit without adversely impacting power quality or reliability under current configurations and without requiring infrastructure upgrades.

I

Information Technology (IT)

Information Technology (IT) uses computers to store, retrieve, transmit, and manipulate data or information, often in the context of a business or other enterprise. Compare with Operational Technology (OT), which uses hardware and software to detect or cause a change through the direct monitoring and/or control of physical devices, processes, and events in the enterprise. Historically, Information Technology and Operational Technology have developed along separate paths, with separate goals, and operating in separate arenas. Today IT/OT integration is happening across numerous sectors and industries. With the increasing sophistication and application of smart grid technologies in the electrical distribution industry, IT applications can now work in tandem with OT applications to increase distribution system performance.

Institute for Electrical and Electronics Engineers (IEEE)

A professional association for electrical engineers and associated disciplines.

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.

Inter-control Center Communications Protocol (ICCP)

An industry standard communications protocol commonly used to connect SCADA, EMS and ADMS solutions.

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 on April 27, 2017, in Docket No. 2013-0141.

Measurement and Verification (M&V)

Measurement and Verification evaluates the energy performance of a resource. The Measurement and Verification process enables the energy savings delivered by a resource to be isolated and fairly evaluated.

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.

Momentary Average Interruption Frequency Index (MAIFI)

Measure of power interruptions for customers who experience a power interruption

N

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.

Non-Wired alternatives (NWA)

As has been discussed in the Companies' Integrated Grid Planning activities, NWAs are electricity grid investments or projects that use nontraditional solutions to defer or replace the need for specific equipment upgrades, such as lines or transformers, by reducing load at a substation or circuit level.

O

Operational Technology (OT)

Operational Technology uses hardware and software to detect or cause a change through the direct monitoring and/or control of physical devices, processes, and events in the enterprise. See Information Technology (IT) entry for further information.

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

Performance-Based Ratemaking (PBR)

A proceeding opened by the Hawaii Public Utilities Commission on April 18, 2018, to collectively investigate linking electric utility revenues with utility metrics.

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 Flow (PF)

See Dispatcher’s Power Flow (DPF).

Power Supply Improvement Plan (PSIP)

The Companies’ December 23, 2016 PSIP Update Report, filed on December 23, 2016 in Docket No. 2014-0183 detailed an action plan for the years 2017–2023 and 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

Remote Fault Indicator (RFI)

Field devices that sense fault current to help determine the location of a fault.

Renewable Portfolio Standards (RPS)

Upon the enactment of SB 2474 established under Act 95 of the Session Laws of Hawai‘i in 2004, the Public Utilities Commission can establish standards that proscribe the portions of electricity generation that shall be met by renewable energy sources. For further information on these requirements, see https://www.energy.gov/savings/renewable-portfolio-standard-4.

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

SAP

Enterprise management system that facilitates workforce management, inventory, customer information, and billing.

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 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.

Switching Order Management (SOM)

A component with the selected ADMS vendor that allows the system operator to create and manage steps utilizing electric grid components to restore customers on outage or to de-energize distribution or transmission circuits for maintenance.

Statement of Work (SOW)

A document that is part of a detailed contract with the vendor that identifies the specific details of the work and the responsible owners for the contracted services.

Supervisory Control and Data Acquisition (SCADA)

A system of remote control and telemetry used to monitor and control the distribution or transmission system and associated substation/feeder automation. D-SCADA refers to SCADA on the distribution system.

System Average Interruption Distribution Index (SAIDI)

Average outage duration for all customers; measured in minutes/hours. Defined in IEEE Standard 1366.

System Average Interruption Frequency Index (SAIFI)

Average number of interruptions experienced by all customers (usually per year). Defined in IEEE Standard 1366.

System Protection

Devices and processes to isolate trouble and "protect" system equipment from dangerous overvoltage conditions caused by faults and trips. System protection involves the "protection" of the island system from cascading outages that could lead to island-wide blackouts. Together with "circuit protection" is sometimes simply referred to as "protection."

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.

Trouble Call Management

A module for accepting and recording trouble calls from customers. This includes outage and other trouble conditions.

Trouble Order Management

An outage management function that performs automatic grouping of trouble calls into trouble orders that represent the calls that are likely due to a common cause. Trouble orders can be sorted by multiple factors for restoration prioritization. Trouble Order Management includes a geographical map display for the System Operator. The OMS then coordinates associated trouble orders through SAP Work Orders to provide specific instruction and coordination to restoration field crews.

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.

Volt-Var Optimization (VVO)

A software module that accesses the advanced meter data for both operational/situational awareness and system studies. Also sometimes called Integrated Volt-Var Control (IVVC).

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.

Workforce Management System (WMS)

Module of SAP, which provides work order details for field crews for system restoration based on the distribution operator dispatches, guided by the ADMS. The WMS also provides workforce management for other business processes.

Exhibit K

GMS Phase 2 ADMS and Field Device Application

Siemens Field Device Strategy

Hawaiian Electric - Grid Modernization

Field Device Strategy
Device Placements

Line sensors and secondary VAR controllers and substation SCADA

February 2021
Hawaiian Electric

Project Reference	Hawaiian Electric Field Device Strategy 2.1.docx
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Revision History

Author (Name)	Department	Contact	Issue	Date
P. Daoust, S.Paoli, D.Eagle	Si DG PTI		1.0 - Released	2021.02.08
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Executive Summary

Hawaiian Electric has engaged Siemens to develop a strategy for the deployment of field devices for the operational areas of Oahu, Maui County, and the Island of Hawaii.

The project was conducted over a four-month timespan where Siemens worked closely with stakeholders at Hawaiian Electric to develop a field device strategy that would support Hawaiian Electric's Grid Modernization Strategy and reinforce the Advanced Distribution Management System (ADMS) application with the Public Utilities Commission.

This project focused on the deployment of substation SCADA, primary line sensors, secondary VAR controllers, and secondary line sensors across all Hawaiian Electric's service territories. The deployment of Advanced Metering Infrastructure as well as other field device types (i.e., intelligent switches, smart fuses) are the focus of adjacent projects underway at Hawaiian Electric.

The field devices are an integral part of the Grid Modernization Strategy and necessary for the ADMS to return value to the organization. The field devices provide the ADMS and the system operator with the field measurements to better identify energization states on the network, identify outages more promptly and enable for effective field crew dispatch, switching and increase operational efficiencies. The field devices also support engineering and planning in validating models and identifying necessary mitigation to ensure efficient network operations.

The deployment of secondary VAR controllers, in scope for this project, also serve a critical function in increasing distribution feeder hosting capacity. The secondary VAR controller are active devices which will allow for direct intervention and better management of the voltage levels on the feeder. Areas with high Distributed Energy Resource (DER) penetration (most commonly PhotoVoltaic generation) commonly experience difficulties in maintaining voltage levels within tolerances which adversely affects the localised ability to host or accept further DER connections. These technical difficulties can be alleviated by the action of the VAR controllers.

This field device project was completed in two consecutive project phases. The first phase focused on establishing the strategy of device deployment which informed the second phase which was to define the field device deployment roadmap. This strategy component, which forms part of the larger Grid Modernization Strategy identified the objectives, business use cases, prioritized benefits and requirements associated with the field devices in scope. This informed the development of the roadmap which provides Hawaiian Electric with an understanding of the number of devices, the distribution feeders most in need by relative priority and an initial estimate as to how many devices are to be installed annually across a five-year deployment timeline to meet the targets.

The outputs of the roadmap can be seen in the table below which identifies the total number of devices identified to be installed over a five-year deployment timeline.

Total Number of Devices Over 5 Years

Device	Total Feeders Identified	Oahu Devices	Hawaii Devices	Maui County Devices	Total Devices
Primary SCADA Relay	**194**	141	39	14	**194**
Primary Line Sensor	**24**	19	-	5	**24**
Secondary VAR controller	**57**	750	-	675	**1,425**
Secondary Line Sensor	**532**	3,141	1,098	549	**4,788**

To develop further grid modernization execution plans based on this strategic direction, Siemens recommends that the field devices roadmap be placed into action with the immediate next step being to commence the detailed design for device placement. This will contribute to the improvement of visibility and situational awareness and support the ADMS in returning value to the business and its customers.

1 Project Overview

Hawaiian Electric has filed an application with the Public Utilities Commission (PUC) for an Advanced Distribution Management System (ADMS) as part of the Grid Modernization Strategy (GMS). To support the evaluation of the ADMS application, the PUC has requested Hawaiian Electric to provide a roadmap for the deployment of the field devices on which the ADMS application depends. Field devices are an integral part of the Grid Modernization Strategy and necessary to achieve the full value of the ADMS.

This Field Device Deployment Strategy is intended to supplement the other strategic initiatives of the Grid Modernization group in the support of the ADMS filing to the PUC. Further details of the ADMS application for which this strategy supports is described in section 2.1.

Hawaiian Electric intends to deploy multiple types of field devices and has grouped the planning and deployment according to the device type and the issue that is being addressed. Each device type will deliver a different range of functionality to the utility in support of the grid modernization objectives. This document is focused the deployment of **secondary VAR controllers, primary line sensors, secondary line sensors and additional substation SCADA** across all Hawaiian Electric's service territories. Section 5.2 provides an outline of the various devices and the associated functionality they provide.

The field devices in focus for this project will serve three main purposes. Firstly, the field devices will support the ADMS system in returning business value through increased situational awareness. This is accomplished by the field devices delivering telemetry to the operations control center. The system operator and the ADMS will be able to utilize the field measurements to better identify energization states on the network, identify outages more effectively enabling for effective crew dispatch, switching and operational efficiencies.

Secondly the field devices support planning engineers in managing the design and efficient operation of the network feeders. This specifically relates to the devices returning field telemetry which will allow for planning and forecasting feeder models to be improved permitting better identification of existing challenges and approaching issues and thus allowing for the implementation of mitigation actions and network design changes.

The third main purpose of the devices is that the secondary VAR controllers are active devices which will allow for direct intervention and better management of the feeder voltage levels. Areas with high Distributed Energy Resource (DER) penetration (most commonly Photovoltaic generation) commonly experience difficulties in maintaining voltage levels within tolerances which adversely affects the localised ability to host or accept further DER connections. This is especially challenging when considering that the output of embedded PV generation varies largely in mass rapidly at the beginning and end of the solar cycle at times when local load is substantial. New inverter functionality such as volt watt and volt var, will help contain the growing challenges of hosting high concentrations of DERs however, there remains the need to address the current challenge and manage the existing infrastructure. The secondary VAR controllers provide a solution by enabling direct mitigation and support of feeder voltage levels for areas in need. This supports grid operations and is an integral part of achieving grid modernization.

The field device strategy detailed in section 4 details the reasons why the project is needed to support the grid modernization objectives and why the in-focus device types are being deployed. This section also articulates what benefits are expected to be realized in support of grid modernization. A structured approach is provided which enables traceability between the objectives, use cases and the benefits derived from the functions provided by the field devices. Also included is a benefits-tracking approach which outlines which metrics are to be recorded to quantify the effectiveness of the devices to return value and further optimize the device deployment.

The Roadmap found in section 5 of this document describes what devices should be deployed on the network and where on the grid the devices should be installed on a per feeder basis, across all Hawaiian Electric's service territories. Also identified is approximately how many of each device will be required to realize the objectives and benefits. The deployment roadmap is defined through a device placement decision process and feeder prioritization matrix found in sections 5.3 and 5.4 respectively which allows multiple criteria and network parameters to be considered when planning device deployment. The roadmap provides Hawaiian Electric with an understanding of the number of devices, the distribution feeders most in need and an initial estimate as to how many devices are to be installed annually across a five-year deployment timeline. The decision process and prioritization tools are designed to be updated with new input data providing an up to date field device deployment strategy as network conditions evolve. This roadmap and the device placement tool position Hawaiian Electric to move forward with the Grid Modernization Strategy and enter the detailed planning and execution of an ADMS system supported by a robust field device strategy.

2 Background & Context

2.1 ADMS Project

Hawaiian Electric's 2017 Grid Modernization Strategy describes the challenges the utility is facing, and the roadmap it has defined to respond to those challenges and opportunities. Several challenges and opportunities arise from the existing and rapid expansion of DER, and more particularly Solar PV. The modernization strategy defines a roadmap[1] of projects over several years – see Figure 1. Customer-Facing technologies (AMI and MDMS) are being addressed in a first phase, while ADMS are addressed in the second phase.

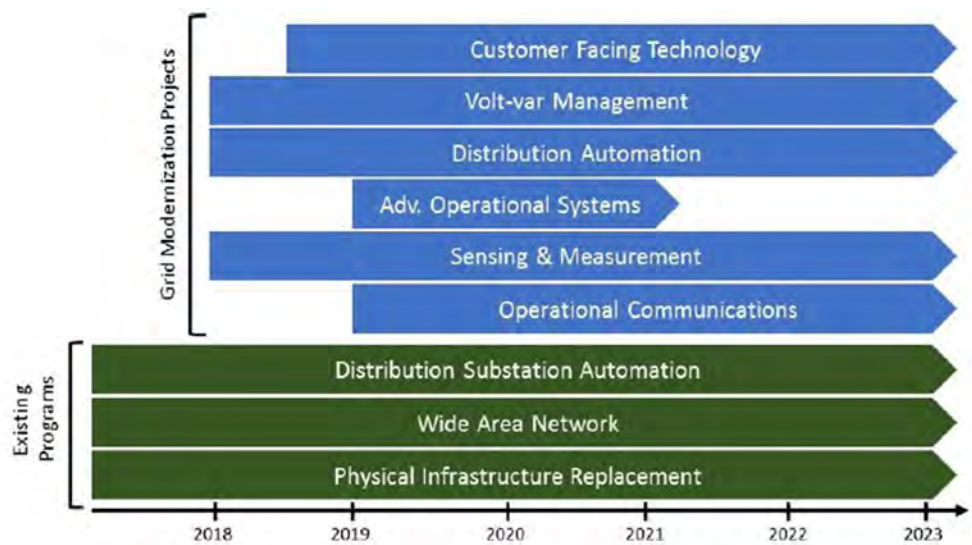

Figure 1: Near-Term Grid Modernization Roadmap

[1] Modernizing Hawai'i's Grid for Our Customers - AUGUST 29, 2017

In 2019 Hawaiian Electric submitted an application to the PUC for the implementation of the ADMS component of the Phase 2 Grid Modernization Strategy. The company expects[2] "[…] the enhanced capabilities enabled by the ADMS will result in numerous customer benefits, including:

- Enabling customer energy options and advancing clean energy goals by providing operational visibility, monitoring, analytics, control, coordination, and automation to facilitate the safe and reliable operation of an electric grid with greater levels of distributed, variable, and renewable generation.
- Improving system reliability and communications by enhancing the ability of the control room to identify the locations and causes of faults, prioritizing outages based on customers affected, and optimizing the dispatch of field technicians; and
- Enhancing operational resiliency and efficiency by allowing operators to analyze distribution grid-edge voltage support and to short-circuit current availability, heightening situational awareness, assisting in restoration triage, and providing a platform that can be used to integrate grid-tied storage batteries and local microgrids.

Hawaiian Electric plans to deploy the ADMS over a four-year period through three releases, with each release layering additional capabilities and more sophisticated controls while maintaining cybersecurity", "[…] Additional capabilities will be required to execute the vision articulated in the Grid Modernization Strategy, including the installation of distribution grid field devices (e.g. remote intelligent switches, remote fault indicators, secondary var controllers, and line sensors) as a component of Phase 2."

Since the field devices analyzed in this project are required to enable the functionality of the ADMS, this Field Device Strategy and associated deliverables aligns with the objectives and benefits defined in the ADMS application.

2.2 Other Relevant Hawaiian Electric Projects

Hawaiian Electric is currently pursuing multiple modernization and investment programs to improve the operations and infrastructure in the utility. The first phase of implementing the GMS is undertaking an AMI and mesh network deployment. The second phase of the GMS is implementing an ADMS

[2] Application of Hawaiian Electric Companies Limited Verification Exhibits A-K

and the overall field device strategy of which this strategy is a subcomponent. In addition, Hawaiian Electric is implementing a reliability strategy, a resiliency strategy, and an asset management and SCADA substation infrastructure upgrade program. Furthermore, the utility communications network is also being analysed for infrastructure upgrades. While Hawaiian Electric is coordinating the numerous work streams it is important to note that several of the programs listed are aiming to make modification to the utility in the same timeframe and are expected to improve similar utility performance metrics such as SAIDI, SAIFI, interconnection experience, renewable portfolio standard achievement, and customer satisfaction. A coordinated effort will be required at Hawaiian Electric to schedule the workstreams and properly allocate the improvements in the key metrics with the multiple programs. This coordination will be essential to plan how to best maximize the benefits returned for the capital being invested.

Beyond the known dependencies and requirements for the coordination of work programs, the installation of additional SCADA infrastructure, line sensors, and secondary VAR controllers will only serve to improve network visibility and grid operations and pose very limited risk to negatively impact parallel efforts in the organization.

It is understood that the distribution network is not a static entity and that additional DERs, including electric vehicle supply equipment, are continuing to be added to the network. Since the analysis presented herein is a ‘point in time’ analysis based on known status at the time, it is possible that the conditions of a feeder are different by the time devices are installed. For example, the need for secondary VAR controller installation may change if additional DERs are connected to the network or depending on the operation and design of DER programs.

It is therefore recommended to re-verify the conditions and expected benefits of each feeder periodically during the planning of the network device deployment. The decision process and prioritization tools described herein have been conceived to accept new input data to ensure to enable the planning functions to adapt to dynamic conditions.

3 Methodology

High-Level Approach

The approach described here was the foundation for the development of the field device placement strategy. The intent of a strategic plan for technology deployment is to maximize the benefits while minimizing risk. A high-level view of the methodology and steps followed for the generation of the Field Device Strategy and Roadmap is illustrated in Figure 2.

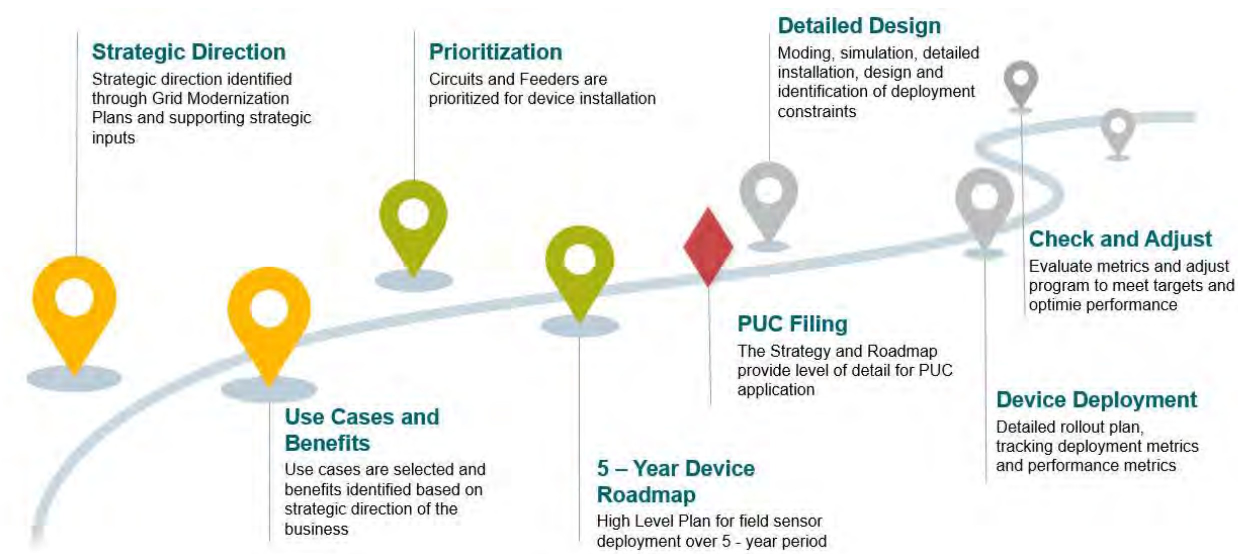

Figure 2: High Level Approach to Strategy and 5 Year Roadmap

Strategic Direction

The framework starts with the utility's strategic direction, plans and current state of business process capabilities. In this case the Grid Modernization Strategy and the ADMS filing provided that direction.

Use Cases and Benefits

Restricted

From this start point a plan was developed through facilitated workshops and analysis to determine how the field devices would support the realization of the business use cases by meeting the technical requirements and return benefits to the business.

Prioritization

With a thorough understanding of the strategic goals, constraints to be managed, and benefits targeted an analytical process was developed to optimize how the how the field devices would be deployed and manage the multiple priorities.

Roadmap

The deployment was span over the 5-year target time frame and placed in priority sequence with a view to perform periodic updates to account for changes in network parameters.

This diamond marks the completion of the field device strategy and initiation of the next phase of implementation planning for the Grid Modernization Strategy.

3.1 Link Between Strategy and Roadmap

It is important to maintain alignment between the prioritization criteria for device placement and the overall strategic objectives at Hawaiian Electric. The approach described uses the objectives defined in the Grid Modernization Strategy as inputs into the analysis. In addition, there is a traceability from the prioritization criteria back to the benefits and the overall strategic goals. Figure 3 illustrates this relationship and describes how the different inputs relate and contribute to the formulation of the deployment strategy.

The diagram in Figure 3: Traceability of Benefits to Objectives shown below illustrates how this project has proceeded to develop a high-level process to determine the placement of field devices, for the device types in focus, on the Hawaiian Electric network in support of the Grid Modernization Strategy.

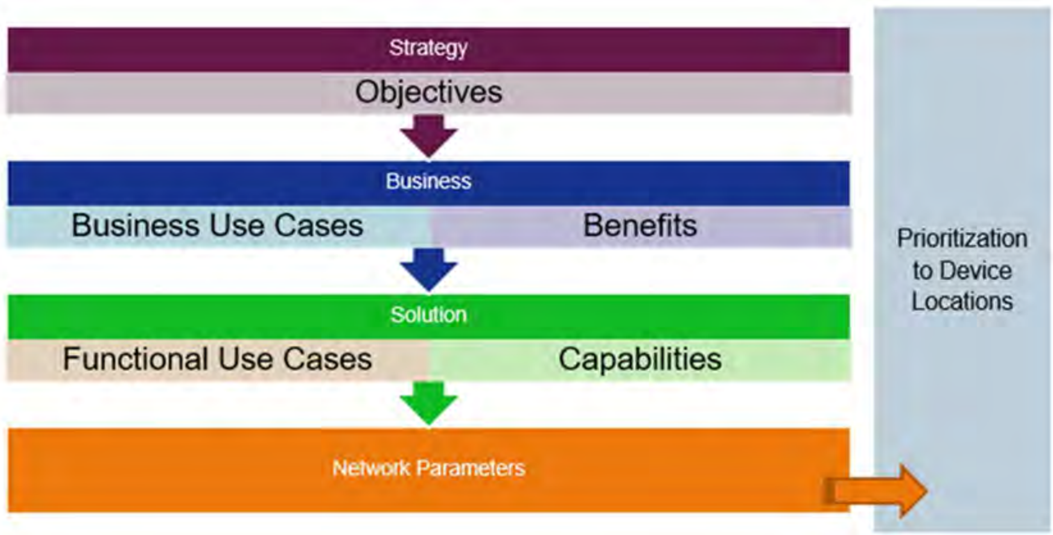

Figure 3: Traceability of Benefits to Objectives

Section 4 of this document describes the elements in the diagram and their interrelation. The subsections describe each stage of the process, the work completed with Hawaiian Electric stakeholders, the outputs produced and how those outputs collectively inform the field device placement strategy. Section 5 describes how the device placement and prioritization was informed and implemented.

4 Strategy

4.1 Approach

To define the field device strategy, the first step aimed at clarifying the purpose and goals of the larger organizational strategy. It received as an input the vision articulated by Hawaiian Electric in GMS and the previous strategy documentation, the current states of the network and the business. The business use cases that relate to field devices were analyzed as well as the functional use cases which would enable the business use cases to be accomplished. Benefits associated with implementing the use cases were assessed and the associated requirements which would need to be met to achieve the desired benefits were assessed.

The diagram below indicates the sequence of elements analysed in the workshops held with the stakeholders at Hawaiian Electric through the strategy development phase of the project. The analysis of the Hawaiian Electric business strategy, business use cases, functional use cases, benefits and requirements are found in section 4.2 to 4.7 respectively.

Figure 4: Steps to Develop Field Device Strategy

4.2 Strategy and Objectives

Hawaiian Electric's high-level direction and objectives are laid out in the GMS. The GMS document also informs how the numerous technology systems will be leveraged to support the Company's long-term plan. The field device strategy has as a starting point the strategy and objectives of the GMS.

Being as the field device strategy is being developed to directly support the ADMS filing with the Public Utilities Commission, the guiding principles, regulatory goals and priority outcomes identified in the ADMS filing are also a direct input to the strategy and objectives of the field device plans.

Below are key references to Hawaiian Electric's documentation which provides the objectives and strategic direction. In developing the field device strategy and determining the prioritization put forward in section 5.4 of this document, Hawaiian Electric applied the GMS guiding principles and ensured alignment with Performance Based Regulation outcomes.

Hawaiian Electric's *guiding principles to inform modernization extracted from the second page of the GMS:*

- 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.
- Determine fair cost allocation and fair compensation for electric grid services and benefits provided to and by customers and other non-utility service providers.

Guiding principles, regulatory goals, and priority outcomes defined by the PUC performance-based rate-making as extracted section 4, sub section E on Page 35 of the ADMS filing submitted to the PUC. ("PBR") framework.33

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The PBR guiding principles include:

- A customer-centric approach
- Administrative efficiency
- Utility financial integrity

The PBR regulatory goals and corresponding priority outcomes are as follows:

- Enhance Customer Experience
    - Affordability
    - Reliability
    - Interconnection Experience
    - Customer Engagement
- Improve Utility Performance
    - Cost Control
    - DER Asset Effectiveness
    - Grid Investment Efficiency
- Advance Societal Outcomes
    - Capital Formation
    - Customer Equity
    - Greenhouse Gas Reduction
    - Electrification of Transportation
    - Resilience

The field devices identified in this strategy generally align with the stated principles and outcomes in a way that allows Hawaiian Electric to continue to build out its grid as a platform and enable many of the outcomes and principles articulated within the PBR proceeding and GMS.

The challenge and opportunity in modernizing Hawaiʻi's electric grid is to serve customers with affordable and reliable electric service while also transforming the system to renewable energy and enabling customers to better control their energy needs. In 2020, approximately 34.5 percent of the Company's combined customers' energy needs were powered by renewable sources, with higher percentages for

Maui County and Hawai'i Island of 50.8 percent and 43.4 percent, respectively. Hawaiian Electric continues to lead the nation in the integration of customer-sited private solar, with the highest percentage of customers with solar of any utility in the country. An estimated 31 percent of single-family homes – had private solar in place by the end of 2020.

4.3 Business Use Cases

A use case-based approach was adopted for this project. The approach is that by implementing a set of business use cases, Hawaiian Electric's strategic objectives will be met. That is to say that the business use cases collectively inform what actions are to be taken by the utility.

The business use cases listed in Table 1 below were extracted from the GMS with the one exception being that use case 10 was elicited during a workshop with the Hawaiian Electric stakeholders. The business use cases focus on Hawaiian Electric's modernization and the use of the ADMS supported by the field devices. The use cases were validated and ranked for their relative priority by the Hawaiian Electric's project stakeholders in a business use case workshop.

Table 1: Business Use Cases Selected

	Business Use Case	Priority	Devices
1	Use improved distribution grid data visibility to manage increasing PV hosting capacity and to manage Distributed Energy Resources	High	SCADA, Primary Line Sensor, Secondary Line Sensor, Secondary Var Controller
2	Use information and communication technological solutions to reduce wire-based upgrades to distribution grid via improved network operations, planning and DR/DER programs.	High	SCADA, Primary Line Sensor, Secondary Line Sensor, Secondary Var Controller
3	Use Advanced Outage Management functions to identify fault locations more quickly and better prioritize restoration resources and activities.	High / Low	SCADA, Primary Line Sensor, Secondary Line Sensor

4	Use FLISR to restore customers more quickly	High / Low	SCADA, Primary Line Sensor, Secondary Line Sensor
5	Use ADMS functions and distributed devices to improve reliability during storm conditions	High / Low	SCADA, Primary Line Sensor, Secondary Line Sensor
6	Provide detailed operating information during emergency situations.	Medium	SCADA, Primary Line Sensor, Secondary Line Sensor
7	Provide updated outage status during normal operation	Low	SCADA, Primary Line Sensor, Secondary Line Sensor
8	Use distribution level data to accurately report outage durations	High / Low	SCADA, Primary Line Sensor, Secondary Line Sensor
9	Incorporate the use of DER assets into contingency planning	Medium	SCADA, Primary Line Sensor, Secondary Line Sensor, Secondary Var Controller
10	Improve planning of capital investments and maintenance programs	High	SCADA, Primary Line Sensor, Secondary Line Sensor, Secondary Var Controller

The business use cases are understood to be high level approaches to meet the strategic objectives and return the targeted benefits. To implement a business use case, the task is broken out to several smaller use cases namely Functional Use Cases (FUC), as described in the following section. The field devices column in the table above indicates which of the four field devices in scope are principally responsible for supporting the implementation of the respective business use cases. The main benefits returned to Hawaiian Electric by the field device strategy and associated to the business use cases can be found in section 4.5 Benefits.

4.4 Business Use Cases Traceability

The Business use case spreadsheet included in the appendix shows the association between the business use cases, the field devices, the functional use cases as well as benefits. The relations between business use cases and functional use cases, devices and benefits are best articulated by an example:

For BUC 01: <u>"Use improved distribution grid data visibility to manage increasing PV hosting capacity and to manage DER"</u>

This business use case can be associated to strategic objectives which include: achieving a renewable portfolio, reducing need for imported oil and providing expanded customer choice.

This business use case can be mapped to the functional use cases ADMS-UC01 *SCADA Events and Alarming* as well as FD-UC09 *Voltage profile improvement for hosting capacity management* amongst others.

The functional use cases can each be mapped to specific solution patterns and technology systems which perform functions to accomplish the use case. For ADMS-UC01 *SCADA Events and Alarming* this can clearly be associated with the addition of substation SCADA relays and switching infrastructure. The additional SCADA relays provide field telemetry to the ADMS enhancing the state estimation which provides the system operator with visibility of field conditions in real time allowing for more effective and informed system operations.

For functional use case FD-UC09, *voltage profile improvement for hosting capacity management* can be associated with secondary VAR controllers. For the purpose of this use case feeder level hosting capacity is defined as: total DER (PV) capacity that can be accommodated on a given feeder without adversely impacting voltage, protection and power quality and with no feeder upgrades or modifications. The secondary VAR controllers supports the functional use case by injecting reactive power to control voltage levels. This action mitigates problems associated with high penetration of PV often experienced as overvoltage. With an improved voltage er profile due to the action of the secondary VAR controller, the feeder is positioned to accept additional DERs (PV).

It should be noted that the functional use cases do not necessarily have a simple one to one mapping towards a technology and may require multiple technology elements to come together to accomplish the use case. This may include telecommunications, data management and analytics systems.

Similarly, there is not a simple one to one relationship between functional use cases and business use case. For example, the BUC *Use Advanced Outage Management functions to identify fault locations more quickly and better prioritize restoration resources and activities* may also be supported by ADMS-UC01.

4.5 Functional Use Cases

An initial set of functional use cases was provided by the ADMS project. As the initial set of use cases focused specifically on the centralized control system, an additional set of functional use cases was created which placed more focus on the Field Devices in this project. This expanded comprehensive set of use case can be seen in the Table 2 below. The use cases were reviewed with Hawaiian Electric stakeholders from across the business and included input from all service territories. The use cases were analysed, updated as needed, and finally ranked by priority. Each service territory ranked the relative importance of implementing the functional use cases according to their local business needs. The differences in the current situation across the service territories indicated that planning a field device placement strategy would be best accomplished by prioritizing the need for a field device on a per feeder basis to account for the regional differences while maintaining a common approach across all service territories.

The later project stages of defining the placement and prioritization design guidelines were informed with an understanding of the relative business needs and how field devices and associated processes and technologies would support the functional use cases and collectively allow the implementation of the business use cases.

Table 2: Functional Use Cases Selected

Number	Functional Use Case	Oahu	Maui County	Hawaii
ADMS-UC01	SCADA Events and Alarming	H	L	L
ADMS-UC02	SCADA Control	H	L	L
ADMS-UC03	SCADA Control System Updates	Out of Scope		
ADMS-UC04	Outage Management	H	H	H

ADMS-UC05	Detect Restoration Issues	H	L	L
ADMS-UC06	Switching Management	H	L	L
ADMS-UC07	Fault Location Analysis	H	H	H
ADMS-UC08	FLISR	H	M	M
ADMS-UC09	State Estimation	H	L	L
ADMS-UC10	Powerflow Studies	H	L	L
ADMS-UC11	Volt/Var Optimization	M	L	L
ADMS-UC12	Load Management	H	H	H
ADMS-UC13	Forecasting	H	L	L
ADMS-UC14	Dynamic Relay Setting	H	L	L
ADMS-UC15	EMS Coordination	Out of Scope		
ADMS-UC16	GIS Updates Workshop	Out of Scope		
ADMS-UC17	Planning	H	H	H
ADMS-UC18	CIS Updates	Out of Scope		
ADMS-UC19	Asset Management Coordination	Out of Scope		
ADMS-UC20	DRMS Coordination	H	L	L
ADMS-UC21	Initial Go Live and Prep	Out of Scope		
ADMS-UC22	High Availability	Out of Scope		

ADMS-UC23	Disaster Recovery	Out of Scope		
ADMS-UC24	Security Event	Out of Scope		
FD-UC01	Collection of operational data for ops situational awareness	H	H	L
FD-UC02	Collecting load profile information for planning DER and load forecasts	H	H	H
FD-UC03	Energy theft detection	Out of Scope		
FD-UC04	Sectionalizing for cold load pickup -SAIDI	Out of Scope		
FD-UC06	Power quality phase balance, PF and THD information capture	M	M	M
FD-UC07	Fire and prevention via fuse replacement	Out of Scope		
FD-UC08	Resiliency via fuse replacement	Out of Scope		
FD-UC09	Voltage profile improvement for hosting capacity management	H	L	L
FD-UC10	Remotely controlled var controller for VVO	M	L	L
FD-UC11	Remotely switched capacitor banks VVO	Out of Scope		
FD-UC12	Conservation Voltage Reduction data inputs	L	L	L
FD-UC13	Reliability improvements via field data asset management (momentary)	M	M	M
FD-UC14	Asset management Tx and feeder load measurements	L	L	L
FD-UC15	Transformer meters for load and temperature management	M	M	M
FD-UC16	Precision Load Shedding	H	L	L

4.6 Benefits

As described in the GMS, the proposed platform will integrate non-replaceable physical infrastructure ("poles and wires") with advanced communications, sensing and measurement, distribution automation, protection, and controls to create a core platform. Applications such as customer advanced metering will leverage this set of core platform technologies. Figure 5 from the Department of Energy (DOE) highlights many of the technologies the Companies are considering to transform the current grid to the grid we need. However, these technologies must be considered in the context of value for customers, and most can be deployed surgically, when and where needed, as identified in the near term rather than as a system-wide deployment.

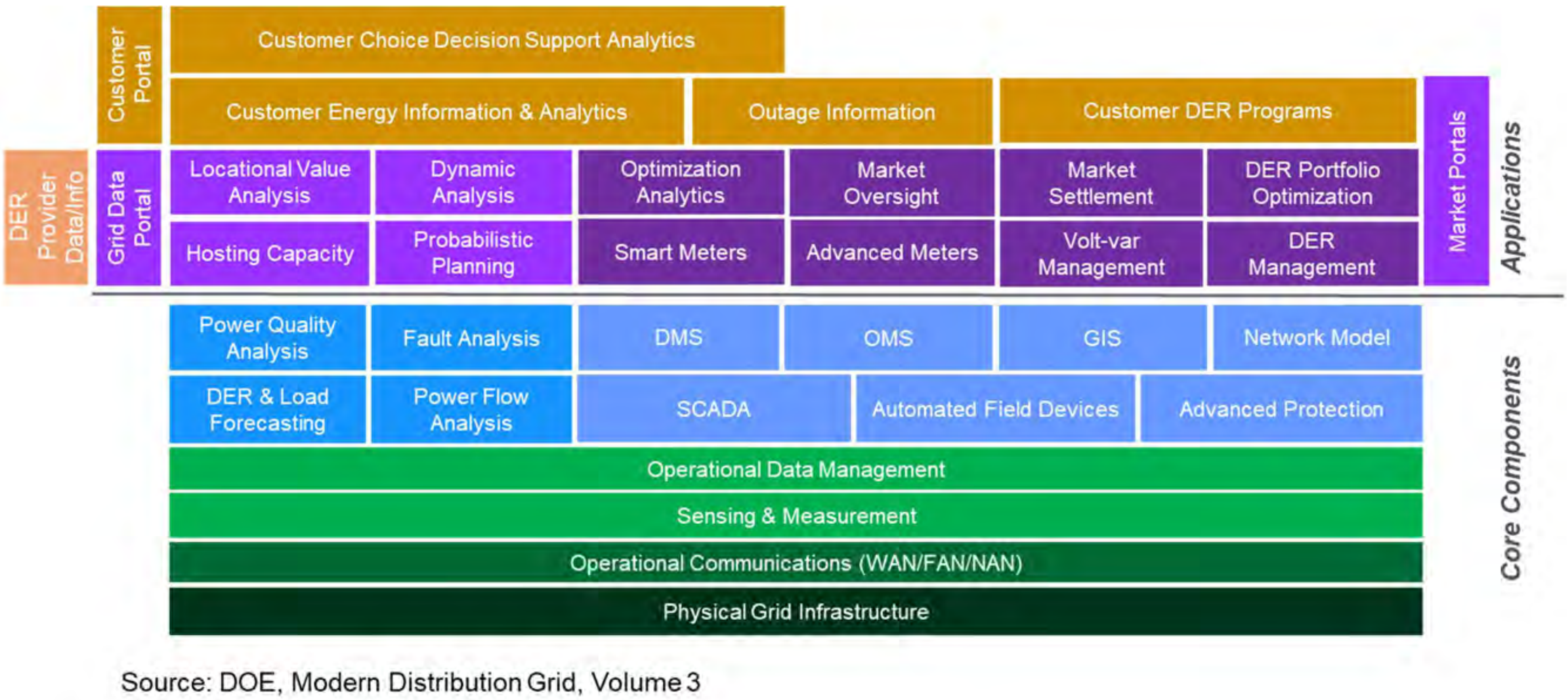

Figure 5: DOE DSPx Next Generation Distribution System Platform

The field device strategy continues the work to lay the foundational core components of the grid as a platform. The field device strategy expands sensing & measurement capability, SCADA capability, improves DER & load forecasting and network models, and enhances applications such as hosting capacity and volt-var management. Figure 6, below, illustrates Hawaiian Electric's current state of grid modernization.

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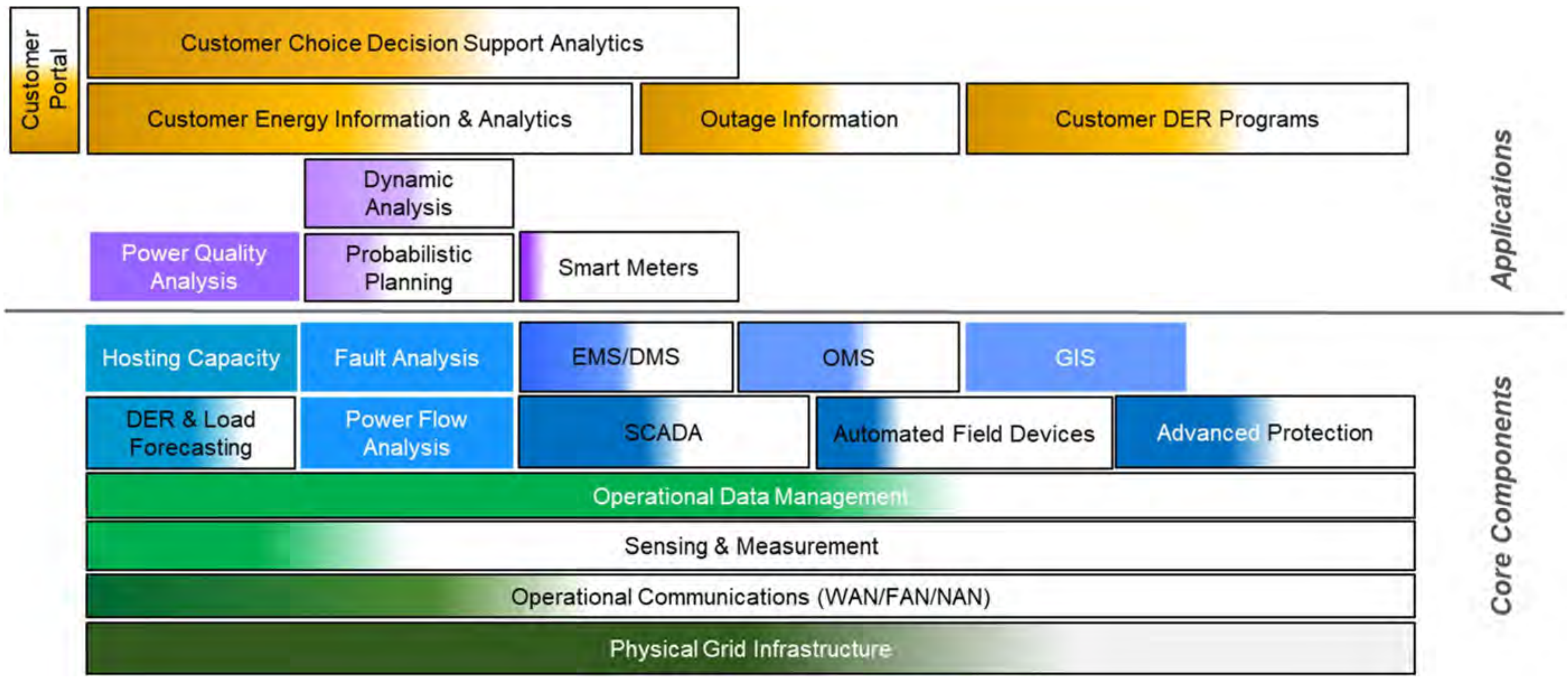

Figure 6: Current State of Grid Modernization

Through implementing the Business use case and the associated functional use cases Hawaii Electric will move toward the grid modernization objectives. As the field devices contemplated in this strategy are foundational, Hawaiian Electric identified qualitative benefits that are expected to accrue to customers. The workshops conducted in this project have produced the list of tangible benefits that are directly related to the deployment of field devices shown in the table 3. Associated with each benefit are the metrics which are to be monitored to evaluate the benefits returned by the implementation of the field device strategy. Benchmarking and tracking the metrics listed over time will allow the field device strategy to be refined over time to meet the evolving needs of the business and also tune the device deployment to ensure the maximum benefits are returned for the capital invested.

Table 3: Benefits Identified

Benefit	Metric
Improved situational awareness	Increase in number of field devices installed
Increased circuit level DER hosting capacity	Increase in feeder hosting capacity (MW)
Improved Power Quality (specifically on areas with high DR/DER program participation)	Identification of number of voltage occurrences outside of Hawaiian Electric Rule No 2 (Character of Service)
Improved modeling and load forecasting	Improved correlation between model simulation results and field measurements
Improved Volt Var Optimization	Improved voltage on feeders where secondary VAR controllers are deployed

There are other indirect benefits that could result of field device deployment. Many of these benefits that were identified through the workshops are already being contemplated as scorecard or reported metric through the PBR framework. Some of these indirect benefits include:

- Improved Reliability. In addition to intelligent switches being deployed as part of the Company's reliability strategy, additional sensing & measurement may help locate faults faster and contribute towards improved SAIDI.
- Reduction in traditional fuel use and GHG. As identified in the table above, increased hosting capacity through better modeling and grid data could allow more customers to cost-effectively adopt DER, which in turn can reduce fuel use and GHG.
- Distribution (grid) capital investment efficiency and Improved planning and efficiency of maintenance programs. Sensing & measurement capabilities can enhance models and planning capabilities, which may allow Hawaiian Electric to more accurately forecast (or defer) new capacity additions to the distribution system. Additionally, the additional sensing & measurement may allow for more accurate characterizations of NWA grid needs.

The benefits listed in table 3 above can also be found in the spreadsheet included in the appendix which tabulates which benefits and associated metrics are linked to the business use cases and the functional use cases. Connecting the benefits to the business use cases and functional use cases was an essential precursor to defining the device roadmap describes in section 5 of the document.

4.7 Requirements

Requirements where collected at the business use case level from the Hawaiian Electric documentation and cross referenced with the Hawaiian Electric stakeholders input through the various workshops. The analysis of the business requirements informed the larger timeframe of the modernization strategy and allowed for a high-level assessment of a capability maturity model for the Hawaiian Electric utility. This informed how the device deployment can be devised to support the grid modernization strategy and permitted for the device strategy next steps in section 6 of this document to be outlined.

Throughout the course of the functional use case workshops and the business benefits workshops operational requirements where discussed for the ADMS system as well as the distribution planning needs of the business. The requirements elicited where used to inform the creation of the device placement decision process and the prioritization approach discussed in section 5. The detailed analysis of the requirements associated with the implementation of each of the functional use cases has been applied in the selection of the parameters found in the scoring and weighting methodology outlined herein.

The distribution planning team has previously completed several field trials with the field devices positioned throughout the course of this project. As such, assessment of technical device level requirements which inform device selection has already been evaluated in previous field trials and was not the focus of this project.

Review of the business needs, in regards to the field device data collected, did however identify the need for a centralized operational data store to permit archiving and retrieval of time series data to facilitate network analysis and planning.

5 Roadmap

5.1 Approach

Outlined in this section is the decision-making approach and prioritization methodology followed to determine which feeders have been assigned to receive field devices for the device types in scope to support Hawaiian Electric's strategic objectives. Section 5.2 describes the devices types in scope. The field device placement strategy analysed the feeder parameters and characteristics and assigned the relative priority of each feeder. The decision process used to assess the key parameters for each feeder and the set of business rules employed to determine the number of devices can be found in section 5.3. The feeders identified to receive Substation SCADA have been assigned a relative priority to inform future initiatives at Hawaiian Electric which will conduct the in-depth analysis to design and plan the execution of the substation upgrades.

Following the device placement, the full list of feeders at Hawaiian Electric have been placed in priority sequence using the prioritization matrix. Section 5.4 of this document describes the prioritization matrix. Section 5.5 articulates the placement and prioritization outputs and assigns the device deployment along a five-year deployment timeline.

Figure 7: Steps to Develop Five-Year Roadmap

5.2 Field Devices

This section provides a high-level overview of the functions provided by the field devices in scope for this project. Descriptions of device functions are provided for distribution field equipment which provide overlapping or supporting functionality to the distribution network which will be relevant when coordinating the global and deployment of all distribution field devices at Hawaiian Electric.

Several device types are identified as providing benefits to situational awareness. To this project that is considered in two parts: benefits for operations and the benefits for planning engineers.

Situational awareness for planning engineers represents timely access to a comprehensive set of time series data of accurate measurements of the distribution feeders which will allow for a clearer understanding of the load profiles and voltage on the feeders and the validation of planning models. This visibility permits an improved understanding of the impacts to feeder voltage levels attributable to DER penetration (typically from Photo Voltaic panels) and what activities are to be planned to manage voltage levels adequately and improve feeder hosting capacity.

Situational awareness from the system operator's standpoint as in the case of SCADA represents the real time status of switch positions and energization states of the network segments. The design approach is that the communications network will be expanded to provide the necessary performance to enable devices downstream from the substation or "in the field" to return high reliability low latency telemetry. This approach will permit readings from the field devices at the grid edge to be used to identify outages and improve the state estimation in the Distribution Management System (DMS). Supporting operational visibility was considered as an input in device placement as described in following sections however, optimizing the performance and functionality of the distribution state estimator and the outage management system is beyond the scope of this project. The detailed analysis of the operational network model and evaluation of the telemetry sources to address the data for accuracy, reliability, latency, quality and completeness in view of planning what actions are to be taken to ensure state estimation algorithms converge providing suitable results is expected to be addressed as part of ADMS implementation.

5.2.1 Field Devices in Scope

The table below outlines the device types that are in scope for this project for which a device placement and deployment approach is provided.

Table 4: Field devices in scope

Device	Functions for ADMS
SCADA relay	Supervisory Control and Data Acquisition relays return measurements of key network parameters on the distribution primary such as Voltage, Current, Power Factor, etc. These measurements improve situational awareness for the system operator and planning engineers. In addition, these relays provide remote control functionality (trip and close) to controllable circuit breakers, reclosers and switches.
Primary Line Sensor	Primary Line Sensors are data acquisition devices which return measurements of key network parameters on the distribution primary such as Voltage, Current, Power Factor. These measurements improve situational awareness for the system operator and planning engineers.
VAR controller	VAR controllers directly inject reactive power on the secondary side of distribution transformers. This serves to manage feeder voltage such as overvoltage issues caused by high penetration levels of distributed energy resources (photovoltaic) and improves feeder DER hosting capacity, or undervoltage due to heavier load conditions. In addition, VAR controllers also provide improved situational awareness for the system operator and planning engineers.
Secondary Line Sensor	Secondary line sensors return measurements of key network parameters such as Voltage, Current, Power Factor. The measurements on the

	distribution secondary improve situational awareness for the system operator and planning engineers.

5.2.2 Field Devices Out of Scope

Table 5 below indicates devices that are not in scope for this project, in that no deployment strategy or roadmap is provided for these devices in this project; however, these devices are under consideration in other company efforts and strategies. The devices are listed for information purposes.

Table 5: Field Devices out of Scope

Device	Functions for ADMS
Smart Recloser	Smart reclosers return measurements of key network parameters such as voltage, current, and power factor. These measurements improve situational awareness. The reclosers provide remote controllable switching functionality. These devices also provide the reclosing functionality of clearing momentary faults and avoiding sustained outages.
Smart fuse	Smart fuses return measurements of key network parameters such as voltage, current, and power factor. These measurements improve situational awareness. The smart fuse can limit the number of persistent outages by clearing momentary faults and avoiding sustained outages. The device will also improve the localizing faults for persistent faults in addition to minimizing the risk of fire associated with blowing standard cut out fuses.
Fault Indicator	Fault indicators provide additional situational awareness by way of indicating to the system operator that fault current was measured on a distribution feeder. The device helps localize faults improving response times for unplanned outages.

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Remote Switch for Capacitor Banks	Capacitor banks are installed in distribution substations or on distribution feeders to manage the power factor and the voltage level on the feeders. Remote switched capacitor banks versus non switched banks can allow system operations to adjust the VAR input level based on network load and DER generation output. Smart capacitor banks can return measurements of key network parameters such as voltage, current, and power factor. These measurements improve situational awareness.
AMI Meters	AMI meters provide improved situational awareness by returning secondary voltage current and power factor readings. The meters can provide measurement inputs to the DMS to support VVO/CVR schemes. The devices inform distribution operations by providing outage notifications and also permit remote disconnect/reconnect capabilities. Additionally, AMI supports customer billing, time of use rates, and other customer energy options.
Smart Voltage Regulators	Voltage regulators serve to manage maintain the voltage on distribution feeders within operational tolerances by adjusting the distribution primary voltage downstream of the substation load tap changer. Smart voltage regulators also return measurements of key network parameters such as voltage, current and power factor. These measurements improve situational awareness. Smart regulators have the advantage of supporting centralized control such that the voltage regulator can be coordinated with substation tap changer, capacitor switching, VAR injection devices and VVO/CVR schemes.

5.2.3 Hawaiian Electric Field Device Experience

This section provides a summary of Hawaiian Electric's experience with field devices in pilot projects and other applications to provide context.

In recent years Hawaiian Electric has been installing several line sensors on its distribution system capable of monitoring steady state voltages and currents at specific identified locations on the grid. Hawaiian Electric deployed Grid 20/20s on Oahu and Maui County while deploying PMI Boomerangs on the island of Hawaii. The sensors were installed largely to monitor areas where high prevalence of PV may be causing voltage violations to customer premises and to determine if PV is the cause of high voltages. In some cases, the sensors were installed to improve distribution power flow models by providing data for model validation.

In partnership with Varentec, Inc., Hawaiian Electric validated the performance of Varentec's technology for managing feeder voltage while allowing more private rooftop solar systems to be added to distribution feeders. A total of four (4) substations on Oahu were chosen for this pilot project with the installation of a little over 150 secondary VAR controllers installed across the substations. The results showed that the secondary VAR controllers provided value for the utility to:

- Maintain secondary voltages in the range of 114V – 126V
- Reduces voltage fluctuations
- Host more solar PV
- Shave peak demand
- Reduces frequent operation of LTC tap due to high PV penetration

5.3 Decision Process

The decision process described in this section defines where on the grid the field devices should be deployed. The criteria for the decisions are derived from the use cases and requirements, from the identified sought benefits, and from the detailed information about the status of the grid at the substation and feeder level. The flow diagrams describe the series of determinations made to identify what devices are required to meet the business needs. The application of devices, on the distribution primary and on the distribution secondary, is executed using the same tool but performed in separate decision processes.

5.3.1 Distribution Primary Device Deployment Decision Process

The process diagram shown below illustrates the decision process followed to determine what primary devices (i.e. SCADA relay or primary line sensor) are needed for each feeder.

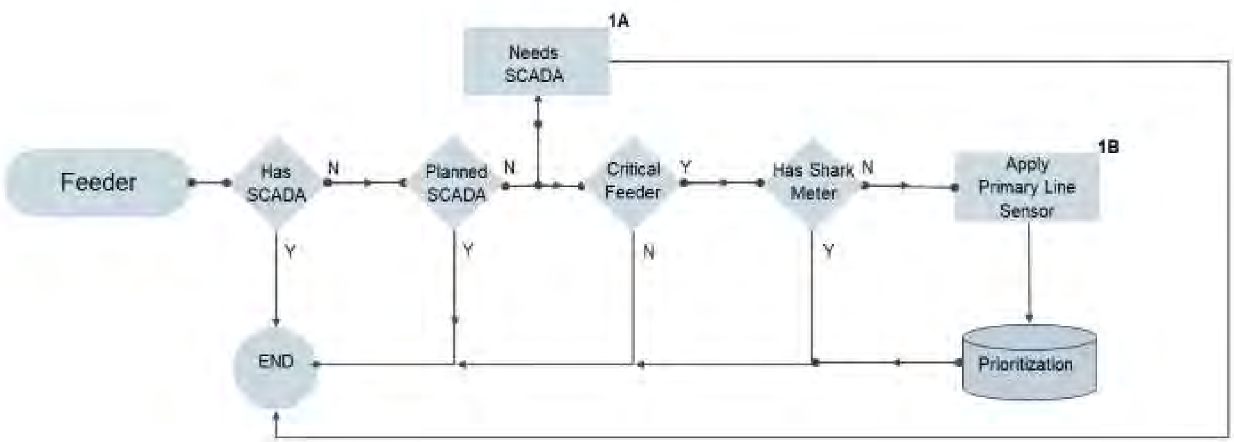


Figure 8: Flow Chart SCADA and Primary Line Sensor 1A 1B

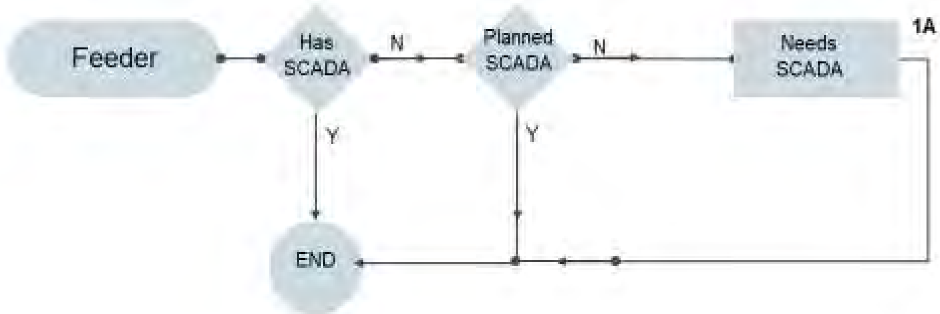
5.3.1.1 1 A) SCADA Relay

Hawaiian Electric's objective is to expand distribution SCADA capabilities across all service territories. Distribution SCADA relays installed in the substations will provide direct situational awareness in real time to the system operator as well as control functionality of the feeder breaker. The operational measurements collected via SCADA on each feeder will enable engineering analysis for planning, the validation of simulation models and reporting.

This project has identified which feeders need distribution SCADA and a priority score has been determined based on the feeder parameters. The prioritization scores are discussed in section 5.4 in further detail. Future projects at Hawaiian Electric will be tasked with the detailed design planning and execution of SCADA upgrades. These future initiatives will be able to utilize the priority scores to inform the planning activities and sequential deployment of SCADA upgrades based on the priority scores.

Within the process diagram in Figure 8 the subprocess to determine **1A** can be seen. The decision to determine if substation SCADA is to be applied to a feeder is straightforward: If a feeder does not currently have SCADA capabilities and there are no current plans to have SCADA installed, then the feeder is identified as being in need of SCADA. This subprocess can be seen in Figure 9.

Figure 9: Flow Chart SCADA Relay 1A



The logical statement which applies to the **1A** decision process is as follows:

[(Has SCADA = No) AND (Planned SCADA = No)] => Needs SCADA

Design and Positioning Notes:

- *SCADA Relay is 3 phase*

It is understood that the SCADA relay installed in the distribution substation is a 3-phase device and will provide real time telemetry (Voltage, Current, real and reactive power, power factor etc.) for all phases.

- *Presence of alternate primary devices*

The presence of reclosers or smart fuses are not seen as a determining factor to identify the need for SCADA as these devices serve different purposes and do not preclude the need for the installation of distribution SCADA.

- Further Sub Prioritization

The prioritization matrix was designed to enable modification and addition of future parameters as the business needs evolve. In the future the prioritization matrix can be updated to factor in the presence of distribution primary devices in the scoring rubric to support further sub prioritization and planning initiatives as required.

5.3.1.2 1 B) Primary Line Sensors (Feeder Head)

Primary sensors are applied to augment situational awareness in areas of need. For this project, primary line sensors are aimed for deployment at the head of critical distribution feeders. A feeder is deemed critical where it supplies a critical load such as a hospital and there is an immediate need to improve situational awareness by returning measurements at the feeder head (i.e. beginning of the of the feeder emanating form the distribution substation).

Applying a primary sensor at the head of a feeder will provide the much-needed visibility for the critical section of the network until such time as the necessary upgrade work in the substation is completed to install SCADA supplying a permanent control and situational awareness solution for the critical circuit. It is understood that the deployment of primary line sensors is a rapid process and can allow for Hawaiian Electric to meet immediate needs while the lengthier design and implementation life cycles for substation SCADA infrastructure upgrades is completed.

This can be seen as the "Apply Primary Line Sensor" in the **1B** item of Distribution Primary Device Deployment Decision Process shown in Figure 8. The decision to determine if a primary line sensor is to be applied to a feeder is straightforward: If a feeder a determined critical and it does not have existing or planned devices (i.e. SCADA relay or Shark meter[3] installed at the substation) that provide sensing at the head of the feeder, then the feeder is identified as being in need of a primary line sensor.

[3] A Shark Meter is a power quality device that the Companies use to monitor voltage, current, watts, and vars at the substation feeder breaker. This device is built into newer substation switchgear packages.

The logical statement which applies in the process and identifies how the data in the prioritization matrix is being used is as follows:

[(Has SCADA = No) AND (Planned SCADA = No) AND (Critical Feeder = Yes) AND (Has Shark Meter = No)] => Apply 1 Primary Line Sensor

Design and Positioning Notes:

- *Primary Line Sensors monitor all 3 phases*

It is understood that the Primary Line Sensors installed at the head of the feeder will provide measurements for all three phases to improve situational awareness.

- *Telecommunications*

This design approach assumes that the necessary telecommunications infrastructure upgrade work will have been completed to provide connectivity to the primary line sensors. The identified locations for primary line sensors will help inform the telecommunication plans.

- *Downstream Situational Awareness of Distribution Primary*

Under current operating conditions at Hawaiian Electric, primary line sensors are targeted for installation at the beginning of distribution feeders “feeder head”. The need for downstream situational awareness of the distribution primary is planned to be provided by alternate distribution devices. The alternative primary distribution devices such as smart reclosers and smart fuses, which also have control functions, are being planned by adjacent projects at Hawaiian Electric. Secondary line sensors will also provide downstream situational awareness. The need for situational awareness and control of the downstream distribution primary are driven by a range of factors including the need to manage feeders which frequently experience unplanned outages (vegetation, salt spray and dust flash over etc.) improved fault location isolation and service restoration via additional switching devices for lengthy feeders or challenging access segments.

- *Redeployment of Primary Sensors*

In the future when distribution SCADA is expanded to a feeder which has had a primary line sensor installed, there is a potential future opportunity to redeploy the primary line sensors to an alternate location to optimize asset use for situational awareness.

5.3.2 Distribution Secondary Device Deployment Decision Process

The process diagram shown below illustrates the decision process followed to determine what secondary devices are needed for each feeder.

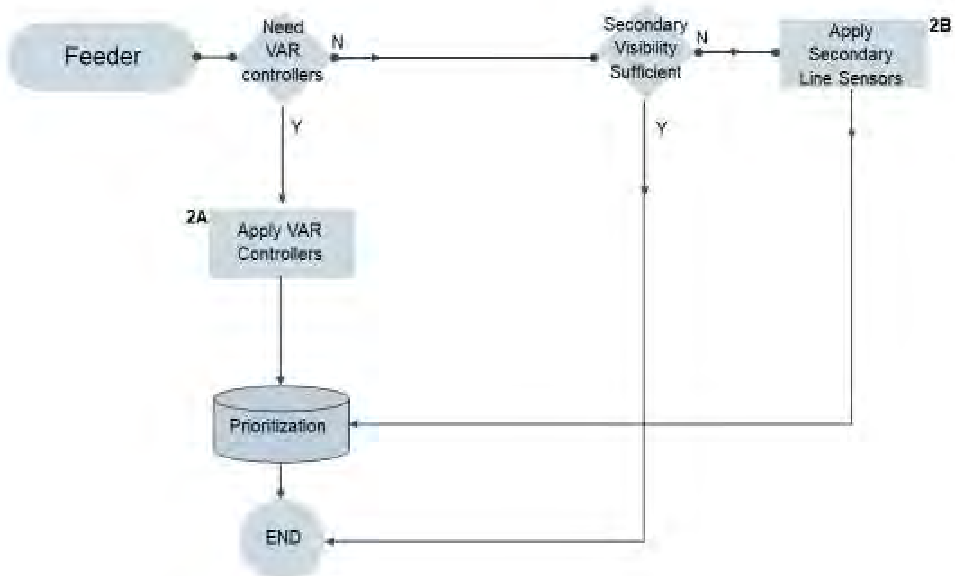


Figure 10: Flow Chart Secondary VAR Controller and Secondary Line Sensor 2A 2B

5.3.2.1 2 A) Secondary VAR Controller

Secondary VAR controllers are applied at network locations where there is a need to alleviate voltage problems via VAR injection. This approach supports compliance with voltage standards (i.e. Hawaiian Electric Rule No. 2 and ANSI C84.1) and can improve the Distributed Energy Resource (DER) hosting capacity of the feeder. Secondary VAR controllers also provide increased situational awareness at their point of installation.

Within the process diagram in Figure 10 the subprocess to determine **2A** can be seen in the figure below. The decision diamond "Need VAR controllers" checks if the feeder is nearing its hosting capacity value and if the hosting capacity is limited due to voltage limitations on the feeder. If both are true then the feeder is identified as being in need of secondary VAR controllers.

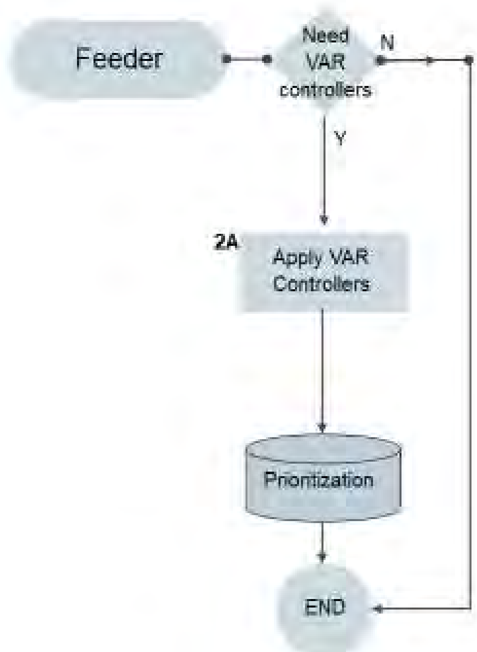


Figure 11: **Flow Chart Secondary VAR Controller 2A**

The logical statement which applies in the process and identifies how the data in the prioritization matrix is being used is as follows:

[(Hosting Capacity Rate >=3) AND (Voltage Limitation = True)]

=> Apply 25 Secondary VAR controllers

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Design and Positioning Notes:

- *Need VAR controllers Gateway AND statement*

The "Need VAR controllers" gateway indicated in Figure 10 and Figure 11 have two conditions connected by an AND statement as can be seen in the logic statement. The files attached in the appendices provide a full operational view of the data utilized as well as formulas employed. The actual need for VAR controllers will be determined through additional detailed analysis as described below due to the locational dependency and many ways voltage issues can be mitigated. For the purposes of prioritizing VAR controller needs, the above flowchart was used as an initial screening tool.

- *Voltage Limitation*

The Voltage Limitation criteria is verifying if the hosting capacity of a feeder is constrained due to a forecasted steady state voltage issue.
If (DER Hosting Capacity < Operational Circuit Limit) {Then Voltage Limitation = True }

- *VAR Controller Business Rules Device Ratio*

Based on previous secondary VAR controller pilot projects the business rules applicable to the positioning of VAR controllers are that for each feeder found to be in need of VAR injection 25 devices are to be applied. 25 devices is approximately the mean installed per feeder in previous pilot projects.

- *Root Cause determination prior to installation*

Prior to designing the detailed installation for secondary VAR controllers, the engineer will ensure root cause of the known voltage problems is determined to validate that the application of a VAR controller is the suitable mitigation approach. This will include a data analysis of the voltage problems. This typically will involve assessing the patterns of the voltage problems (reoccurring at similar points in the daily load curve e.g. linked to DER activity) and if there are associated power quality issues such as flicker and phase imbalance. VAR controllers may not necessarily be the only solution, there are other solutions that may be considered to resolve voltage issues that include, but not limited to, upgrading conductors, balancing generation and load per phase, non-wires alternatives, etc. Hawaiian Electric will evaluate the solution of best fit on a case by case basis.

- *Detail Design*

Following the high level device positioning to allocate devices to feeder on a needs basis, detailed design will be undertaken to determine the exact location (e.g. identifying specific poles) for the VAR controller and to account for local field conditions (access, pole condition, vegetation etc.). At the time of defining the detailed installation location the distribution designer will conduct an assessment on a per feeder basis to validate the optimal location and numbers of VAR controllers. Where necessary detailed modeling and simulation of the feeder will be conducted to adjust the default design guideline of 25 devices per feeder accordingly.

- *Relative device cost and device deployment*

Preliminary cost factors indicate that secondary line sensors are approximately a third of the cost of VAR controllers. Where the needs are mainly to improve situational awareness the secondary line sensors will be the solution pursued.

- *Underground feeders and Secondary VAR Controllers*

The secondary VAR controllers considered for this project are devices intended to be installed on overhead distribution infrastructure (pole top). Where a feeder has been identified as underground a flag has been entered in the prioritization tool to indicate that the feeder is to be placed on hold for deployment. This approach enables the device needs (device count) and priority to be assessed for planning purposes on all feeders but allows the deployment on underground feeders to be scheduled separately when the secondary VAR controllers for underground feeders are commercially available..

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5.3.2.2 2 B) Secondary Line Sensor

Secondary Line sensor provide situational awareness at their point of installation. The telemetry returned informs based on the data at the point of measurement on the distribution secondary and also provides insight as to the distribution primary due to the fact that it is possible to transpose secondary readings to the distribution primary via the turn ratio of the distribution transformer. At feeder locations where there is a need to increase the situational awareness and VAR injection is not required, secondary line sensors will be targeted for installation provided that other devices are not planned to be installed in the near future which would fill the needs to provide sufficient situational awareness of the secondary network. One such example would be adequate coverage of AMI along the feeder. Ongoing updates of the prioritization and scheduling of secondary line sensors will need to occur periodically to ensure coordination with the AMI deployment. The prioritization tool described in the following section includes was conceived to allow for such continuous refinement of device deployment prioritization.

The logical statement which applies in the process and identifies how the data in the prioritization matrix is being used is as follows:

[(Secondary VAR Controller = No) AND (Planned AMI = No) AND (Existing AMI = No) AND ('Situational Awareness Secondary score >= 25)] => Apply 9 Secondary Line Sensors

Design and Positioning Notes:

- *Secondary Visibility Sufficient Gateway AND statement*

The "Secondary Visibility Sufficient" gateway indicated in Figure 10 has multiple criteria connected by an AND statements as can be seen in the logic statement. The files attached in the appendices provide a full operational view of the data utilized as well as formulas employed.

- *Situational Awareness Secondary Score*

The "Situational Awareness Secondary Score" determines whether the feeder has sufficient monitoring on the secondary. Based on the parameters in this category as shown in Table 7, a feeder will have a score greater than or equal to 25 if there is secondary monitoring on all three phases at the beginning, middle, and end of the feeder.

- *Secondary Line Sensor Business Rules Device Ratio*

Based on previous device trials the business rules applicable to the positioning of secondary line sensors are that for each feeder found to need improved situational awareness 9 devices are to be applied to meet the feeder needs. The approach is to install secondary line sensors at three locations along the length of the feeder in groups of three (one per phase on a three-phase feeder) for situational awareness (3 X 3 devices).

- *Detail Design*

Following the high level device positioning to allocate devices to feeder on a needs basis, detailed design will be undertaken to determine the exact location (e.g. identifying specific poles) for the sensors and to account local field conditions (access, pole condition, vegetation etc.). At the time of defining the detailed installation location the distribution designer will conduct an assessment on a per feeder basis to validate the optimal location and numbers of secondary line sensors are applied and adjust from the 9 sensor per feeder design guideline accordingly. Detailed design will include a verification to determine if feeders which have received VAR controllers need additional secondary line sensors.

- *AMI Meters*

AMI meters provide situational awareness of the secondary network at their metering location. As such where AMI meters are present the design assumption is that AMI meters are deployed in batches on a per feeder basis (i.e., proportional deployment strategy or opt-out) at sufficient density to meet the minimum threshold of coverage and collectively provide sufficient situational awareness that secondary line sensors will not need to be applied. However, there may be situations where it is beneficial to have both AMI meters monitoring power quality at a customer premise and have monitoring at the distribution service transformer that serves those customers. For example, for problematic areas it may be useful to know the voltage drop and volatility between the service transformer and individual customer premises to determine the best solution to mitigate voltage problems. This is especially true in older neighborhoods where the secondary design was done at a time when customer loads were lower and less volatile. A symptom of this type of design is having many customers than is typical today connected to a single service transformer that may lead to more voltage volatility.

5.3.3 Summary Table of device placement

The table below summarizes the device placement according to the device type, functions, positioning logic and the number of devices per identified feeder in need.

Table 6: Summary of Device Placement

Device	Device Positioning	Functions	Logic
SCADA Relay (Primary)	1A	Control of distribution circuits via remote switching Data acquisition for situational awareness	[(Has SCADA = No) AND (Planned SCADA = No)] => Needs SCADA
Primary Line Sensor	1B	Data acquisition for situational awareness	[(Has SCADA = No) AND (Planned SCADA = No) AND (Critical Feeder = Yes) AND (Has Shark Meter = No)] => Apply 1 Primary Line Sensor
Secondary VAR controller	2A	Improved voltage via VAR injection Data acquisition on distribution secondary	[(Hosting Capacity Rate >=3) AND (Voltage Limitation = True)] => Apply 25 Secondary VAR controllers If (DER hosting Capacity < Operational Circuit Limit) { Then Voltage Limitation = True }
Secondary Line Sensor	2B	Data acquisition for situational awareness	[(Secondary VAR Controller = No) AND (Planned AMI = No) AND (Existing AMI = No) AND ('Situational Awareness Secondary' score >= 25)] => Apply 9 Secondary Line Sensors

5.4 Circuit Priority

This section articulates the criteria and tool that allows Hawaiian Electric to prioritize the locations and feeders for the field device deployment.

A complete list of feeders was assembled for the Hawaiian Electric service territories (Oahu, Maui County, and Hawaii); this list of feeders represented the entire network. The number of circuits included in the final analysis and prioritization is 658, with the following breakdown for the three territories:

- Oahu: 403
- Hawaii: 145
- Maui County: 110

Analysing the distribution network on a per feeder basis provided a detailed view of each set of local conditions present on the network and enabled the resulting device positioning and prioritization to account for localized variations.

Key feeder parameters were identified which provide pertinent information about the feeder characteristics. The parameters were grouped and categorized into five main prioritization objectives as described in more detail in section 5.4.1. The parameters in the Additional Factors Considered objective are used in the device decision process described section 5.3. The parameters were used to assist in the device placement as well as to support the prioritization and preparation of a deployment strategy.

5.4.1 Feeder Parameter and Prioritization Objective Selection

The methodology behind the selection of feeder parameters, categorization and grouping of parameters into prioritization objectives and the application of weightings to those objectives is what determined the relative priority of the feeders and established the guiding principle of the device placement strategy. The methodology was established through several workshops with the Hawaiian Electric subject matter experts. The work performed in the previous project phase to establish the links between the strategy, business use cases, functional use case, benefits, and benefit metrics is what informed the selection and use of feeder parameters for the prioritization. In many instances the grouping of feeder parameters to prioritization objectives directly relate to the strategic objectives.

Also, several of the parameters used in the prioritization directly mirror the metrics identified to track device benefits returned. There is however not a direct relationship as a level of expert judgement was required to select parameters from the data available and those key performance indicators that are tracked. Where certain parameters were not available at a uniform level for all Hawaiian Electric service territories alternate parameters were used.

As a result of consultation with data stewards from several business areas at Hawaiian Electric, extensive discussion with the Hawaiian Electric subject matter experts a list of all feeder parameters was assembled. The table below provides a description of the parameters that factored into the prioritization.

Table 7: Feeder parameters for analysis and prioritization

Objective	Feeder Parameter	Description
Feeder identification	Island	Service territory: Oahu, Hawaii, Maui County
	Substation	Name of the substation at the feeder head
	Primary Voltage	Primary Voltage of the feeder (kV)
	Circuit	Unique identifier for the feeder
	Longitude/Latitude	Geolocation of feeder head, used for visualizations
	Dedicated	Yes/No
Criticality	is_critical_circuit	Yes/blank, circuit identified as critical by system operations and planning
	customer_count	Number of customers served
	peak_demand	Peak Demand (kW)
	load_growth	Expected yearly growth of load (%)
Reliability and PQ issues	SAIDI	Circuit SAIDI (number)
	SAIFI	Circuit SAIFI (number)
	PQ_problems_count	Power Quality problems (Voltage Sags & Swells) (number)

	future_needs	Yes/No, Areas identified with grid needs due to future load growth and potential voltage concerns from the Honolulu Rail Transit Project
Situational Awareness Primary	has_scada	Yes/No
	smart_switch_count	Number of smart reclosers and intellirupters devices existing on the feeder (number)
	has_shark	Yes/No, Shark branded power monitor installed at the head of the feeder
	smart_fuse_count	Number of smart fuses devices existing on the feeder (number)
Situational Awareness Secondary	boomerang_count	Number of boomerang devices existing on the feeder (number)
	Grid2020_count	Number of Grid2020 devices existing on the feeder (number)
	AMI_existing	Yes/No, if AMI meters existing on the feeder
	Varentec_count	Number of Varentec devices existing on the feeder (number)
Feeder Hosting Capacity	hosting_capacity_kW	Amount of hosting capacity on the feeder (kW)
	DER_growth	Forecasted DER growth over next 5 years (%)
	has_Voltage_limitation	Yes/No, if "Operational Circuit Limit" is higher than "Internal Capacity".
Additional factors considered	planned_new_recloser_count	Number of new reclosers planned on the feeder (number)
	AMI_planned	Yes/No, if AMI meters are planned on the feeder
	planned_new_smart_fuse	Yes/No, if a new smart fuse is planned on the feeder
	scada_planned	Yes/No, if SCADA is planned on the station hosting the feeder

Several input raw data files were collected, processed, and merged to gather data for all parameters as per table above. A complete list of feeders and network parameters can be found in the files attached as referenced in the Appendices.

The device placement process described in the previous section leveraged the feeder list populated with the feeder parameters to execute the device placement process and identify which feeder were to receive which devices according to the business rules described in previous sections.

Following the device placement, the full list of feeders was prioritized for relative importance identifying which feeder would receive precedence to have the identified devices installed. This was accomplished based on a method of weighted scoring of the feeder parameters. This device placement tool and weighted prioritization scoring is referred to as the Prioritization Matrix.

The matrix is a combination of the raw data held in a series of excel spreadsheets and python scripts which manipulate and analyse the data. A diagram explaining the simplified function of the prioritization matrix in terms of its inputs and outputs is depicted in Figure 12.

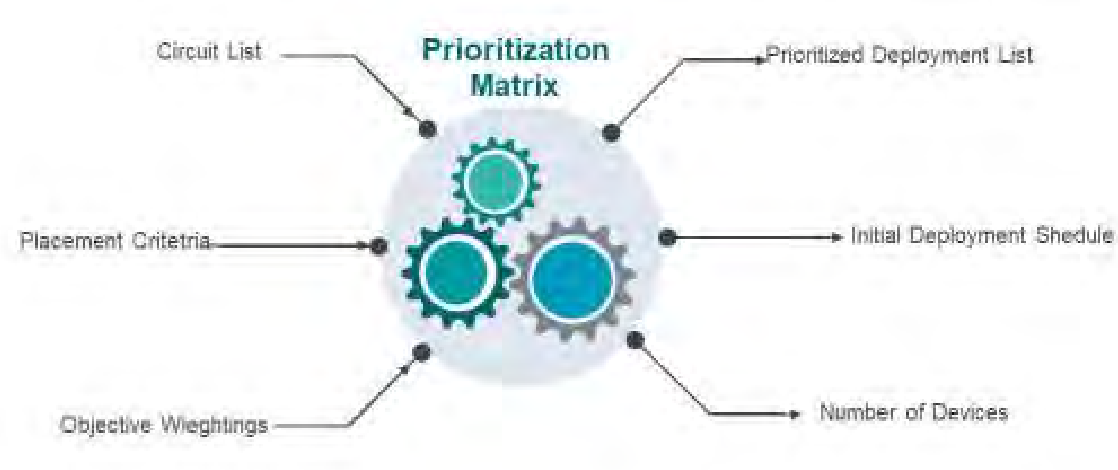

Figure 12: Prioritization Matrix Functional Diagram

5.4.2 Feeder List and Raw Data

The many input raw data files have been processed and merged to produce a single spreadsheet that includes all circuits and all parameters on distinct columns in a single table. That file "circuits_data_summary.xlsx" is attached as part of the Appendices. Figure 13 shows a sample portion of that file.

[redacted]

Figure 13: Sample image of the raw data file

5.4.3 Quantification of parameters

Each input parameter needs to be "normalized" to be comparable to the others. Such normalization is achieved by converting the parameter values into "Rates". The rate is an integer value 0 to 3 and the formula to translate from parameter value to rate is indicated in Appendix 6.1 Device Prioritization Matrix.

5.4.4 Weightings of parameters

The circuit ranking (or priority) is obtained by using a weighted sum of all parameter scores.
With reference to Table 7, the parameters are first aggregated (using sub-weights, column "I" of Appendix 6.1 Device Prioritization Matrix) to produce an objective score:

- Criticality
- Reliability and PQ Issues
- Situational Awareness Primary
- Situational Awareness Secondary
- Feeder Hosting Capacity

The objective scores are then aggregated (using weights, column “C” of Appendix 6.1 Device Prioritization Matrix) to produce a final score: aggregate_score. See appendix 7.3 for further details.

The values of parameters sub-weightings and objective weightings are contained in the spreadsheet “device prioritization matrix.xlsx”, of which Figure 14 provides a sample image.

Objective	Weight	score	Parameter/Input	Field in data file	Description	Value	Weig	Rate	Rate formula	Comments	Source file
Data used to identify feeders and prioritize the need for a field device											
Feeder identification (Data used to identify the feeder)											
Scoring Objectives (Objectives and paramenters used to determine prioritization score for the feeder)											
Criticality	25	100									
			Criticality Index	is_critical_circuit		Yes/blank	75	2,0	Yes=2, 0 otherwise	Include circuits that need Shark; Table 2 in "IOC - S	"Oahu Sys Ops Critical Circuit I
			Number of Customers	customer_count		number	10	2,1,0	3 equal-width bins: 0=lower, 1=medium, 2=high number	If blank default to median across circuits	T&D Planning Field Dev Strat -
			Peak demand	peak_demand		number (kW)	10	2,1,0	Peak/customer_count; 3 equal-width bins: 0=lower, 1=medium, 2=high number		Oahu Sys Ops Critical Circuit L
			Expected load growth	load_growth		%	5	2,1,0	3 intervals (0=0% or blank, 1%, 2=2%)	Only for Oahu	"2018 Oahu Load rev2.xlsx"
Reliability and PQ issues	25	100									
			Feeder SAIDI	SAIDI	Circuit SAIDI	number	10	2,1,0	3 bins: 0=0-50%, 1=50-75%, 2=75-100% (due to outlie	Outliers circuit '1212','1283'	T&D Planning Field Dev Strat -
			Feeder SAIFI	SAIFI	Circuit SAIFI	number	10	2,1,0	as for SAIDI	Sensors may help investigate root causes of outag	T&D Planning Field Dev Strat -
			PQ problems (Voltage Sags & Swells)	PQ_problems_count		number	40	2,1,0	3 bins: 0=0-500, 1=500-2000, 2>2000	Outlier stations: AIEA, MCCULLY, KEOLU	PQ Problems'
			Future needs	future_needs		Yes/blank	40	2,0	Yes=2, 0 otherwise	Rail & Grid Needs	<Island> Grid Needs.xlsx'
Situational Awareness Primar	12.5	100									
			SCADA controlled breaker	has_scada		Yes/No	30	2,0	Yes=0,No=2		circuits_master_list
			Existing Smart Switches	smart_switch_count	# Smart Reclosers + Intellirupters	number	20	2,1,0	0 if count>1, 1 if count=1, 2 if count=0		Intellirupter List.xlsx'
			Existing Shark meter	has_shark	If Sharks present on circuit	Yes/No	30	2,0	Yes=0,No=2	has_shark=Yes if value="Shark"	Shark Meter List (Oahu)rev1.xl
			Existing smart fuses	smart_fuse_count	# of devices on the circuit	number	20	2,1,0	0 if count>1, 1 if count=1, 2 if count=0		Smart Fuse and Smart Reclos
Situational Awareness Secon	12.5	100									
			Existing line sensors	boomerang_count	# of devices on the circuit	number	25	2,1,0	0 if count>=9, 1 if 1<=count<=8, 2 if count=0		Boomerang List_Hawaii 12142
			Existing Grid2020	Grid2020_count	# of devices on the circuit	number	25	2,0	0 if count>=9, 1 if 1<=count<=8, 2 if count=0		Maui Grid 2020 Count.CSV' ar
			Existing AMI meters	AMI_existing		Yes/No	25	2,0	Yes=0,No=2		Circuits With AMI.xlsx'
			Existing Varentec controller	Varentec_count	# of devices on the circuit	number	25	2,0	0 if count>=1, else 2 (equivalent to Yes/No)		Varentec ENGO List.xlsx'
Feeder Hosting Capacity	25	100									
			Hosting Capacity	hosting_capacity_kW		number	60	3,2,1,0	4 buckets: 3: 0-250kW (or null),250-1000,1000-3000, 0 if >3000		Calculated Circuit Values 1118
			Expected DER growth (future penetrati	DER_growth	Forecasted growth over next 5 years	%	40	3,2,1,0	4 buckets: 0=null or 0-5%, 1=5-10%,2=10-14%,3=>14%. The growth is over year, not yearly		"DER Growth rev1.xlsx"
			Voltage Limitations	has_Voltage_limitation	"Operational Circuit Limit" is higher th	Yes/No			Not rated. Used as a flag for decision on 'Secondary VAR Controller'		"Calculated Circuit Values 111
Total score	**100**										
Modifying factors (Factors that can alter the score, e.g. deem a device not needed no matter what its score is.)											
Planned Upgrades (next 12 months)											
			Planned Recloser	planned_new_recloser_co	# of devices on the circuit	number					Feeder Projects_vAM3'
			Planned AMI meter	AMI_planned		Yes/No					Circuits With AMI.xlsx'
			Planned Smart Fuse	planned_new_smart_fuse		Yes/No					Future Smart Fuse List Hawaii
			Planned SCADA	scada_planned		Yes/No					Switchgear Replacement.xlsx

Figure 14: Sample Prioritization Matrix

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5.4.5 Scoring and Circuit Priority Results

The file "circuits_data_summary_with_scores.xlsx" is attached to this deliverable. Figure 15 shows a sample portion of that file. This file is the result of the Prioritization Matrix providing the total aggregate score for all feeders along with the ranking for each parameter shown in Table 7.

	A	B	C	BR	BS	BX	[redacted]	BZ
1	Island	Substation	Circuit	Varent	situational_awareness_secondary_score	hosting_capacity_score	[redacted]	ggregate_score_rank
2	Hawaii	[redacted]	[redacted]	50	100	40	[redacted]	[redacted]1-40
3	Hawaii	[redacted]	[redacted]	50	87.5	80	[redacted]	[redacted]1-60
4	Hawaii	[redacted]	[redacted]	50	100	60	[redacted]	[redacted]1-40
5	Hawaii	[redacted]	[redacted]	50	100	60	[redacted]	[redacted]1-40
6	Hawaii	[redacted]	[redacted]	50	100	40	[redacted]	[redacted]1-40
7	Hawaii	[redacted]	[redacted]	50	100	20	[redacted]	[redacted]1-40
8	Hawaii	[redacted]	[redacted]	50	100	60	[redacted]	[redacted]1-40
9	Hawaii	[redacted]	[redacted]	50	100	80	[redacted]	[redacted]1-60
10	Hawaii	[redacted]	[redacted]	50	100	100	[redacted]	[redacted]1-60
11	Hawaii	[redacted]	[redacted]	50	100	100	[redacted]	[redacted]1-80
12	Hawaii	[redacted]	[redacted]	50	100	60	[redacted]	[redacted]1-60
13	Hawaii	[redacted]	[redacted]	50	100	100	[redacted]	[redacted]1-60
14	Hawaii	[redacted]	[redacted]	50	100	60	[redacted]	[redacted]1-40

Figure 15: Sample image from the prioritization matrix

This file represents the result of this study and provides the feeders' priority for device deployments.

Appendix 7.6 contains tables extracted form the prioritization matrix, for each island and device type.

5.4.6 Updates

The decision-making tool allows for a dynamic context, in which the conditions can change over time (e.g. changes in the amount of DER installed on a feeder). Updating the input data described above and modifying the relative weights on a needs basis will enable a re-prioritization of the feeders based on up to date state information.

5.5 Device Deployment Roadmap

The output of the decision process and prioritization matrix provided the following results in terms of device numbers.

5.5.1 Device Numbers

The tables below indicate the total number of distribution feeders selected for deployment of devices and the number of units for each device type to be deployed on those feeders.

Table 8: Number of Feeders Selected for Deployment

Device	Oahu	Hawaii	Maui County	Total feeders
Primary SCADA Relay	141	39	14	**194**
Primary Line Sensor	19	-	5	**24**
Secondary VAR controller *	30	-	27	**57**
Secondary Line Sensor	349	122	61	**532**

Table 9: Number of Devices Deployed

Device	Units per feeder	Oahu	Hawaii	Maui County	Total devices
Primary SCADA Relay	1	141	39	14	**194**
Primary Line Sensor	1	19	-	5	**24**
Secondary VAR controller *	25	750	-	675	**1,425**
Secondary Line Sensor	9	3,141	1,098	549	**4,788**

* Note: numbers for VAR controllers will be updated in the detailed design stage.

5.5.2 Device Deployment

For each device type, the total number of units to deploy has been distributed and allocated to the five years roadmap following the assumption that an approximate equal number would be deployed across each of the five years. This assumption can be refined as Hawaiian Electric plans the installation and more detailed information on budgets and operational constraints become available. The one exception being that the 24 primary line sensors are all designated for deployment in year 1 as the manageable number of devices and substantial advantages provided by the devices motivate the accelerated deployment.

The tables and figures in the below subsections show the deployment numbers for each of the primary and secondary devices. The specification of deployment year for each circuit is determined by its aggregate score in the prioritization matrix. Circuits with the same priority are allocated to the same year, which is why the device installed per year are different, as opposed to equal across the years. As stated above, the specification of the exact number of devices and the selection of feeders among the ones identified in the ranking will be done at design and deployment time based on a more complete operational view.

5.5.2.1 Substation SCADA

The feeders identified to receive Substation SCADA have been assigned a relative priority and placed for context only. The intent is to inform future initiatives at Hawaiian Electric which will conduct the in-depth analysis to design and plan the execution of the substation upgrades. Planning Substation SCADA upgrades in not in scope of this study, however the prioritization matrix is a powerful tool which can be applied to support the planning and execution of the SCADA deployment.

5.5.2.2 Primary Line sensors

Primary sensors are to be applied to augment situational awareness by collecting telemetry at the head of feeders for circuits where there is an immediate need to provide the system operator and planning engineer with improved visibility. The additional telemetry will enable planning engineers to validate and improve their network models in addition to supporting the state estimation tool. The intent is to install primary sensors on critical feeder until the more complex SCADA upgrades can be designed and implemented which will provide not only visibility but also the ability to remotely execute direct switching operations. The device placement has identified 24 feeders which do not currently have SCADA, do not have a plan in place to install SCADA and are deemed critical feeders.

Table 10 below shows the preliminary primary sensor deployment taking place in the fist year. The 24 devices installations are estimated to be very manageably completed in the fist year of the deployment. The application of the primary line sensors is accelerated to address the immediate needs to provide improved situational awareness of the critical feeders to the systems operator and will enable planning engineers to represent circuit modeling more accurately, particularly for critical circuits with high DER penetration.

Table 10: Number of primary devices deployed per year

Primary Line Sensor Device		Total Number	Year 1	Year 2	Year 3	Year 4	Year 5
SCADA	**Total**	**194**	**33**	**40**	**28**	**50**	**43**
	Oahu	**141**	26	13	23	41	38
	Hawaii	**39**	1	24	4	8	2
	Maui County	**14**	6	3	1	1	3

Primary Line Sensor	**Total**		**24**	**-**	**-**	**-**	**-**
	Oahu	**19**	19	-	-	-	-
	Hawaii	**-**	-	-	-	-	-
	Maui County	**5**	5	-	-	-	-

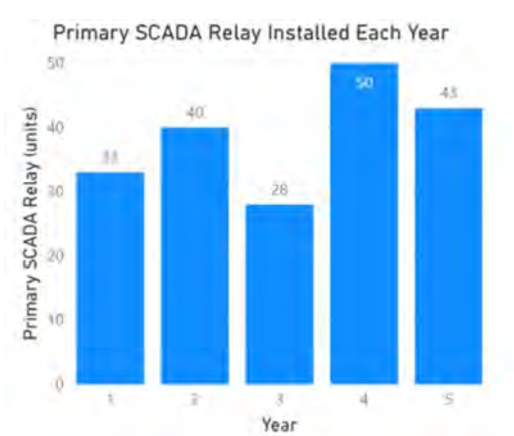

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Figure 16: Number of SCADA devices deployed in the five years

5.5.2.3 Secondary VAR Controllers

The results for the decision process for secondary VAR controllers initially identified a total of 81 feeders in need for mitigation action. Currently, secondary VAR controller devices on the market are designed for overhead distribution connection. Underground solutions are in development and its efficacy has not been tested by Hawaiian Electric. Therefore, an additional screen was placed on the 81 identified feeders to filter out feeders that are mostly underground resulting in a new total of 57 feeders. This represents 1,425 devices installed across the five-year time span as illustrated below. The approach is to install 25 secondary VAR controllers on the feeders in need. The ratio 25 secondary VAR controllers was determined as approximately the average installed on a feeder based on previous pilot projects which have taken place at Hawaiian Electric.

Table 11: Number of Secondary VAR Controller Devices Deployed per Year

Secondary VAR Controller	Total	Year 1	Year 2	Year 3	Year 4	Year 5
Total	**1,425**	**300**	**225**	**275**	**300**	**325**
Oahu	**750**	75	100	125	200	250
Hawaii	**-**	-	-	-	-	-
Maui County	**675**	225	125	150	100	75

Figure 17: Total Number of VAR Controllers Deployed

5.5.2.4 Secondary Line Sensors

Of the total 658 three phase feeders analysed 532 feeders have been identified as being in need of additional situational awareness in order to more accurately determine load profiles, DER contributions and validate the planning models in view of improving network operations. As described in section 5.3.2, 9 single phase secondary line sensors are applied per feeder. Table 12 describes how the 4,788 devices are distributed on priority basis across the 5-year device deployment timeframe.

Table 12: Number of Secondary Line Sensors Deployed per Year

Secondary Line Sensor	Total	Year 1	Year 2	Year 3	Year 4	Year 5
Total	**4,788**	**900**	**918**	**945**	**774**	**1,251**
Oahu	**3,141**	630	558	540	477	936
Hawaii	**1,098**	162	288	297	135	216
Maui County	**549**	108	72	108	162	99

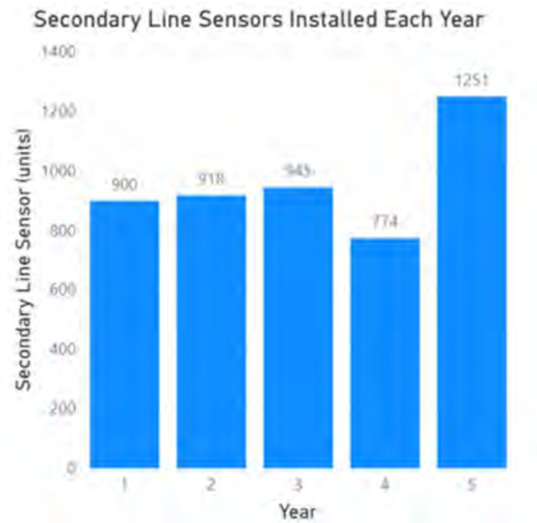

Figure 18: Total Number of Secondary Line Sensors Deployed

5.5.3 Visualizations - Island Maps

The visualization tool developed in Power BI offers a convenient way to visualize the recommended deployment roadmap. As shown in sample figures below for each island, the tool allows to filter on each type of device and deployment year, thereby allowing to understand and improve the deployment roadmap based on logistical considerations.

Oahu:

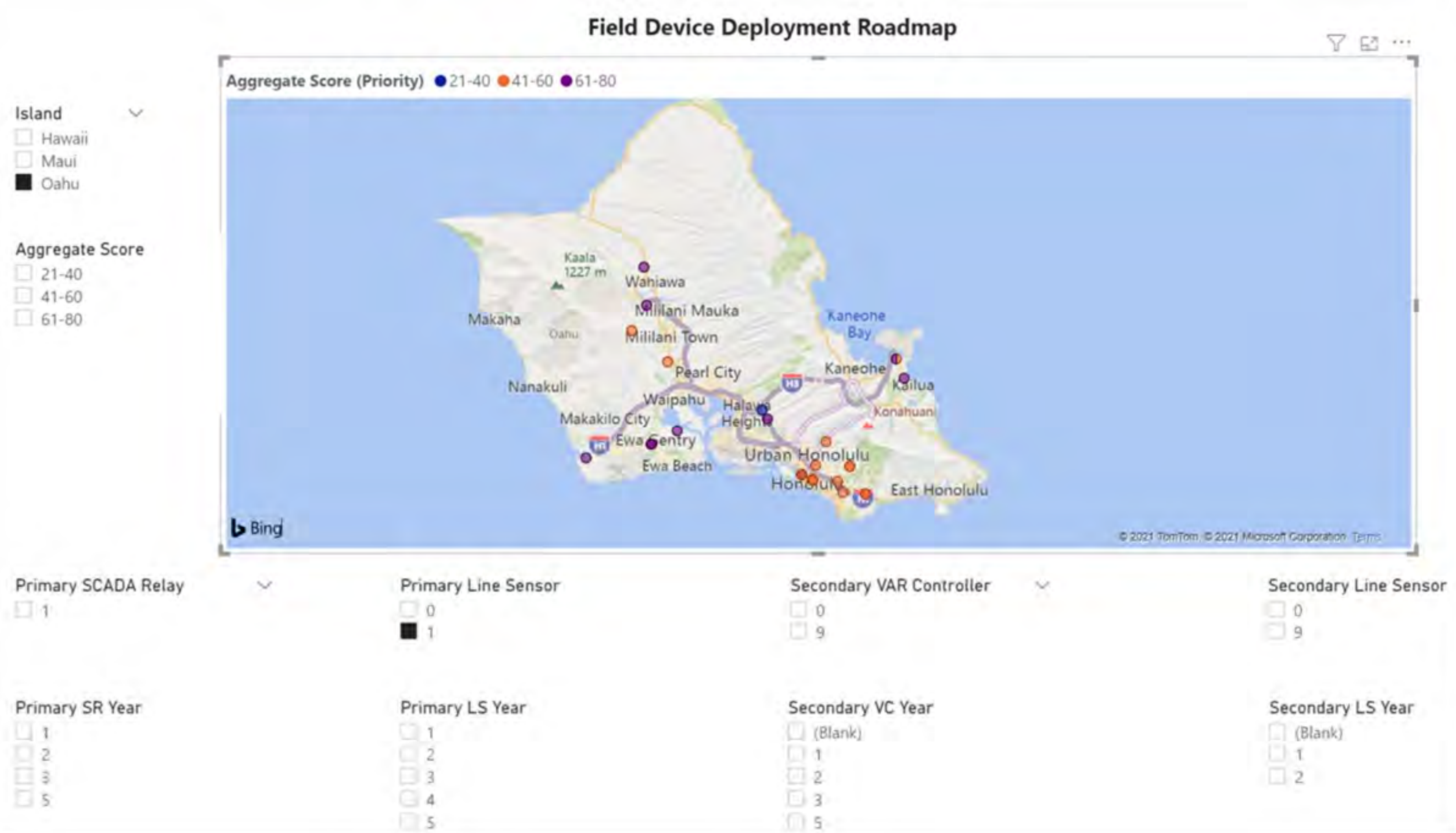

Figure 19: Visualization of deployment roadmap on Oahu

Note: the radio buttons below the map allow to filter on each device type and the deployment year for each type. The figure has been filtered to show feeders prioritized for Primary Line Sensors; selecting one year in the slicer below would show the feeders scheduled for Primary Line Sensor deployment on the selected year. (SR=SCADA Relay, LS=Line Sensor, VC=VAR Controller)

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Island of Hawaii:

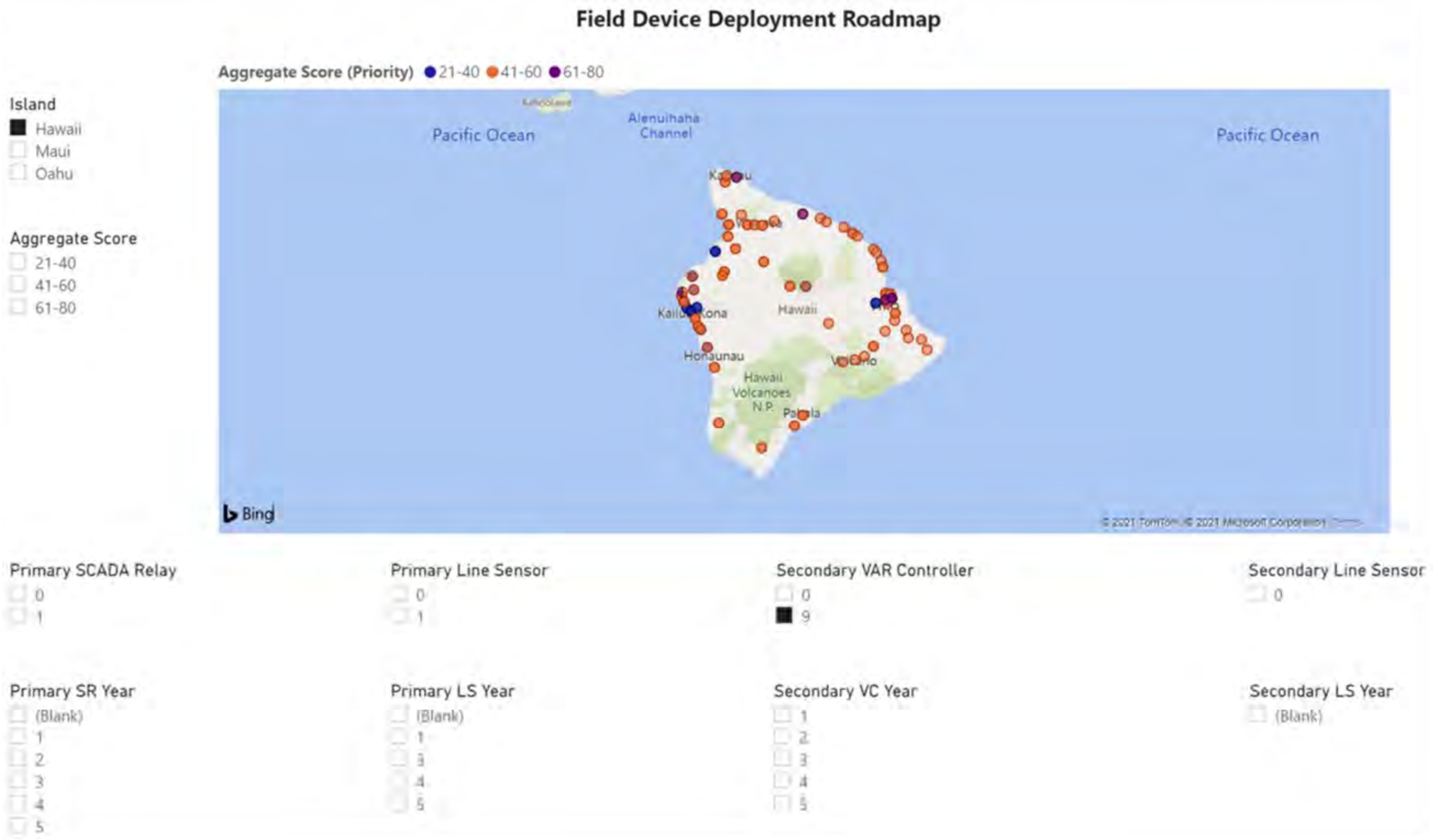

Figure 20: Visualization of deployment roadmap on the island of Hawaii

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Maui County:

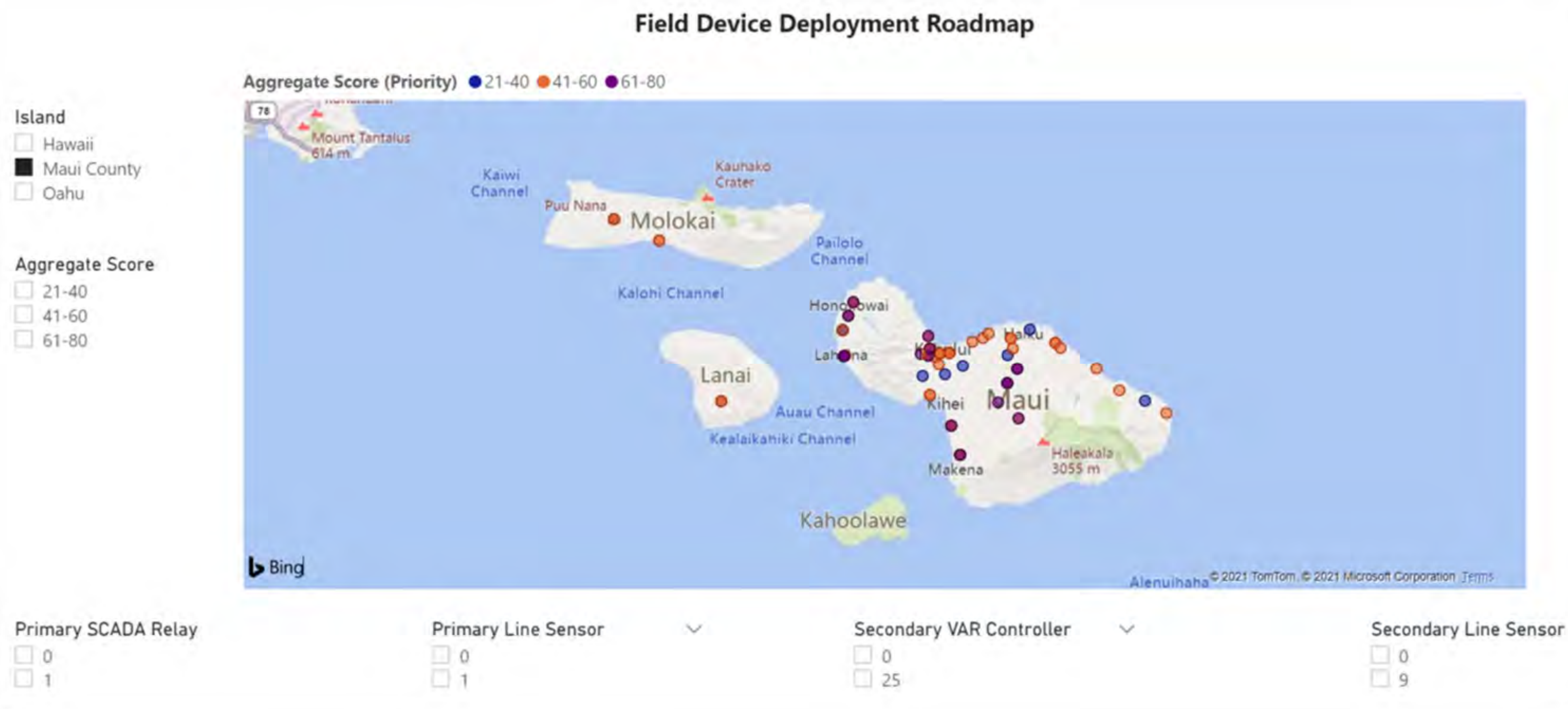

Figure 21: Visualization of deployment roadmap on Maui County

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6 Next Steps

This field device strategy is intended to support the planning of the grid modernization at Hawaiian Electric. This field device strategy and placement roadmap provides high level direction for the deployment of field devices to support the ADMS implementation and benefits realization. To develop further grid modernization execution plans based on this strategic direction, Siemens has provided the following for future consideration.

6.1 Detailed Design and Device Deployment Planning

The subsequent steps for the field devices will be to undertake detailed design and scheduling for the field device installations as a future project. This will entail:

- Further subdividing the annual deployments into phases
- Identifying the specific locations for individual devices (e.g. pole selection)
- Analysing field telemetry to assess the root cause of any voltage violations
- Conducting modeling and power flow simulations to validate default placement numbers and update with feeder specific designs
- Evaluate if alternate solutions are applicable on a per feeder basis to support device deployment such as conductor upgrades
- Performing the necessary preinstallation site inspections
- Coordinating device deployment with parallel efforts such as tap changer optimization and additional distribution smart device installation
- Estimating the installation costs and resource requirements
- Putting in place resourcing, contracting and procurement plans
- Allocating the installation to work packages (work orders, material packages, installation scope and instructions etc.)
- Devising a work scheduling and permit /outage coordination scheme for device installation
- Installing the devices in the initial phase and collecting initial data streams to validate the placement designs and models and update the deployment plans accordingly
- Executing a deployment monitoring and performance optimization program

- Proceeding with subsequent deployment phases informed by previous phase performance metrics

At the completion of the 5-year deployment period all feeders are intended to have the assigned field devices installed to meet the project objectives in support of the larger strategic goals of the utility.

6.2 Check and Adjust

Given the distribution systems are constantly changing (i.e., economic development, DER adoption, EV adoption, etc.), the prioritization and deployment schedule is ideally reassessed **(check and adjust)** on a periodic basis to account for changes in field conditions. The device placement process and prioritization matrix were designed to provide Hawaiian Electric with tools which can be updated with recent field data and used to inform the evolving planning and design process.

The Prioritization Matrix (spreadsheet and python scripts) described in section 5 is the tool that was used to identify the location on the network where field devices should be deployed. It is used to prioritize installation at a feeder level based on a 'prioritization score' assigned to each feeder in Hawaiian Electric's service areas. The prioritization score is derived from the workshop exercises of analyzing and ranking the use cases and benefits articulated in Section 4. This tool is intended to be periodically updated as Hawaiian Electric proceeds through subsequent planning and deployment phases with recent input data in order to recalibrate the deployment plan, to reflect deployment state, current network state and updated plans.

Changes in field conditions which need to be managed includes not only the standard parameter changes, such as criticality load and customer count on a per feeder basis, but also consists of the addition of field devices installed by other programs at Hawaiian Electric that may also have sensing capability. The additional devices to consider include smart reclosers, smart fuses, AMI meters, and additional SCADA which would affect the level of situational awareness and priority of some network sections. Furthermore, a change in network topology which may involve the addition of a feeder to the network can be accommodated by the prioritization tool as both the input data and prioritization parameters can be updated to accommodate such changes.

6.3 Telecommunications Connectivity for Field Devices

Hawaiian Electric's telecom strategy is in development and will in the future aim to plan which telecom infrastructure approaches will be adopted in which sequence across the service territories. The current methodology in terms of the field device strategy is to move forward with identifying which distribution feeders are in need of field devices with the understanding that the telecom infrastructure expansion in its upcoming planning phase will prioritize network areas most in need of improved communications to provide the required connectivity to the field devices. This design assumption is critical to be validated as the value the field devices provide to the organization and effectiveness of the ADMS system are dependant on the ability of the ADMS to receive telemetry from the field devices. For instance, the performance of the distribution state estimator in the DMS is directly related to the quality of telemetry provided. The primary line sensors outlined in this strategy will need to have a high-performance secure communications connection. This means a data stream which has low latency, can support high read rates and is reliable in terms of availability and minimal missing data packets. It will be essential that the telecommunications design teams and field device deployment team have well coordinated planning project executions.

7 Appendices

7.1 Appendix A – Project Stakeholders

Given the far-reaching impact of the deployment of field devices across the Hawaiian Electric grid, a wide group of business units have a stake in the project and the resulting strategy and roadmap. Many stakeholders have participated to the project. Table 13 indicates the business units that were represented by participating stakeholders and a summary of their stake in this project.

Table 13: Business Unit Stakeholders

Business Unit	Stake in project
Asset Management	Devices provide the capability to evaluate the health of assets
Enterprise Architecture & Planning	As is and future system architecture state in which these devices will be deployed
Investment Planning & Strategy	Managing the overall device strategy.
Operational Technology	Regulatory and technical stand of point.
Operations Planning & Construction Management	Managing the overall Grid Modernization Strategy
System Operations	Location of devices will support the operation and situational awareness of the grid more effectively and efficiently.
System Planning	As business owner, the output of this project support delivery of distribution planning program.
Telecommunications	Device locations will be an input the Telecom plan by identifying areas with communication needs.

7.2 Appendix B – Strategy Traceability Workbook

See attached file: "Business UC sheet.xlsx"

7.3 Appendix C - Device Prioritization Scoring and Calculations

The attached Excel file **"device prioritization matrix.xlsx"** provides details of all parameters that have been considered for the circuit prioritization, and relative weights and rating formula.

With reference to Table 7, the following table shows the rating formulas and sub weights for each parameter. Rates and weight are needed to be able to compare among parameters of different nature.

Table 14: Rating and Weightings for Parameters for Feeder Prioritization

	Parameter / Field in data file	Value	Sub Weight	Rate	Rate formula
Criticality					
	is_critical_circuit	Yes/blank	75	2,0	2: Yes, 0: blank
	customer_count	number	10	2,1,0	3 equal-width bins: 0=lower, 1=medium, 2=high number
	peak_demand	number (kW)	10	2,1,0	Peak/customer_count; 3 equal-width bins: 0=lower, 1=medium, 2=high number
	load_growth	%	5	2,1,0	3 bins: 0: 0% or blank, 1: 1%, 2: 2%
Reliability and PQ issues					
	SAIDI	number	10	2,1,0	3 bins: 0: 0-50%, 1: 50-75%, 2: 75-100% (due to outliers)
	SAIFI	number	10	2,1,0	as for SAIDI
	PQ_problems_count	number	40	2,1,0	3 bins: 0: 0-500, 1: 500-2000, 2: >2000
	future_needs	Yes/blank	40	2,0	2: Yes, 0: blank
Situational Awareness Primary					
	has_scada	Yes/No	30	2,0	2: Yes, 0: blank
	smart_switch_count	number	20	2,1,0	0: count>1, 1: count=1, 2: count=0
	has_shark	Yes/No	30	2,0	2: Yes, 0: blank
	smart_fuse_count	number	20	2,1,0	0: count>1,

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					1: count=1, 2: count=0
Situational Awareness Secondary					
	boomerang_count	number	25	2,1,0	0: count>=9, 1: 1<=count<=8, 2: count=0
	Grid2020_count	number	25	2,0	0: count>=9, 1: 1<=count<=8, 2: count=0
	AMI_existing	Yes/No	25	2,0	0: Yes, 2: No
	Varentec_count	number	25	2,0	0 if count>=1, else 2 (equiva-lent to Yes/No)
Feeder Hosting Capacity					
	hosting_capacity_kW	number	60	3,2,1,0	4 buckets: 3: 0-250kW (or null), 2: 250-1000, 1: 1000-3000, 0: >3000
	DER_growth	%	40	3,2,1,0	4 buckets: 0: null or 0-5%, 1: 5-10%, 2: 10-14%, 3: >14%
	has_Voltage_limitation	Yes/No			Not rated. Used as a flag for decision on 'Secondary VAR Controller'

Weights and scores, with values as in Table 14 and Table 15, are also used to aggregate the objectives' scores into the overall value “aggregate_score”.

Table 15: Weightings of the Objectives used for Prioritization Formula

Objective	Weight	Max score (normalized)
Criticality	25	100
Reliability and PQ issues	25	100
Situational Awareness Primary	12.5	100
Situational Awareness Secondary	12.5	100
Feeder Hosting Capacity	25	100
Max possible score	100	

Table 16 provides an example of calculation of the “aggregate_score” for a sample circuit.

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Table 16: Example Calculation "aggregate_score" for a Sample Circuit

Parameter	Value	Calculated Rate	Sub Weight	Weighted Score
Island	Oahu			
Substation	Generic			
Circuit	Generic Ckt 1			
UG Ckt	Yes			
is_critical_circuit	Yes	2	75	150
customer_count	1	0	10	0
peak_demand	3194	2	10	20
load_growth	0%	0	5	0
criticality_score			(150+0+20+0)/2=	**85**
SAIDI	709	2	10	20
SAIFI	1	1	10	10
PQ_problems_count	407	0	40	0
future_needs	Yes	2	40	80
reliability_PQ_issues_score			(20+10+0+80)/2=	**55**
has_scada	No	2	30	60
smart_switch_count		2	20	40
has_shark		2	30	60
smart_fuse_count		2	20	40
situational_awareness_primary_score			(60+40+60+40)/2=	**100**
boomerang_count		2	25	50
Grid2020_count		2	25	50
AMI_existing		2	25	50
Varentec_count		2	25	50
situational_awareness_secondary_score			(50+50+50+50)/2=	**100**
hosting_capacity_kW	0	3	60	180
has_Voltage_limitation	No			
DER_growth	0	0	40	0
hosting _capacity_score			(180+0)/3=	**60**
aggregate_score	(85*25+55*25+100*12.5+100*12.5+60*25)/100=			**75**

Note that all aggregated scores are normalized to maximum value of 100.

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7.4 Appendix D - Output Visualization File

See attached Power BI file **"HECO_Feeders_Visualizations.pbix"**.

This file provides various visualizations of the data with the tool Microsoft Power BI. The advantage of this tool is that it provides interactive visualizations including maps that can be zoomed to focus on specific areas and feeders.

7.5 Appendix E - Prioritization Matrix Output Files

See attached Excel file **“circuits_data_summary_with_scores.xlsx”**.

This file represents the final result of the study and provides the feeders’ priority for sensor deployments, as well as which devices would be installed in each feeder and in which year.

7.6 Appendix F – Raw List of Feeder Priorities

The following tables are extracted form the prioritization matrix (file "circuits_data_summary_with_scores.xlsx"), for each island and device type. For each device type and each territory, they indicate the circuits requiring devices. The lists are prioritized by the aggregate_score, and the columns Year indicates in which of the five years in the roadmap the devices would be deployed.

Device: Primary SCADA Relay

Total across all territories: Circuits: 194, Total devices: 194

Oahu – 141 circuits, 141 devices Primary SCADA Relay

Island	Substation	Circuit	aggregate_score	Year
Oahu	[redacted]	[redacted]	75	1
Oahu			71	1
Oahu			71	1
Oahu			71	1
Oahu			69	1
Oahu			68	1
Oahu			66	1
Oahu			66	1
Oahu			66	1
Oahu			65	1
Oahu			65	1
Oahu			64	1
Oahu			63	1
Oahu			62	1
Oahu			61	1
Oahu			60	1
Oahu			60	1
Oahu			59	1
Oahu			59	1
Oahu			59	1
Oahu			59	1
Oahu			58	1
Oahu			58	1
Oahu			57	1
Oahu			57	1
Oahu			56	1
Oahu			55	2
Oahu			54	2
Oahu			54	2
Oahu			53	2
Oahu			53	2
Oahu			52	2
Oahu			52	2
Oahu			52	2
Oahu			52	2

Restricted

Island	Substation	Circuit	aggregate_score	Year
Oahu	[redacted]	[redacted]	51	2
Oahu			51	2
Oahu			51	2
Oahu			51	2
Oahu			50	3
Oahu			50	3
Oahu			50	3
Oahu			50	3
Oahu			49	3
Oahu			49	3
Oahu			48	3
Oahu			48	3
Oahu			48	3
Oahu			48	3
Oahu			48	3
Oahu			48	3
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Oahu			47	3
Oahu			47	3
Oahu			47	3
Oahu			47	3
Oahu			47	3
Oahu			47	3
Oahu			47	3
Oahu			46	3
Oahu			46	3
Oahu			45	4
Oahu			45	4
Oahu			45	4
Oahu			45	4
Oahu			45	4
Oahu			45	4
Oahu			45	4
Oahu			45	4
Oahu			45	4
Oahu			45	4
Oahu			45	4
Oahu			45	4
Oahu			44	4
Oahu			44	4
Oahu			44	4

Restricted

Island	Substation	Circuit	aggregate_score	Year
Oahu	[redacted]	[redacted]	44	4
Oahu			44	4
Oahu			43	4
Oahu			43	4
Oahu			43	4
Oahu			43	4
Oahu			43	4
Oahu			43	4
Oahu			43	4
Oahu			43	4
Oahu			42	4
Oahu			42	4
Oahu			42	4
Oahu			42	4
Oahu			42	4
Oahu			42	4
Oahu			42	4
Oahu			42	4
Oahu			42	4
Oahu			42	4
Oahu			41	4
Oahu			41	4
Oahu			41	4
Oahu			41	4
Oahu			41	4
Oahu			41	4
Oahu			40	5
Oahu			40	5
Oahu			40	5
Oahu			40	5
Oahu			40	5
Oahu			40	5
Oahu			40	5
Oahu			40	5
Oahu			40	5
Oahu			39	5
Oahu			39	5
Oahu			39	5
Oahu			39	5
Oahu			39	5
Oahu			38	5
Oahu			37	5

Restricted

Island	Substation	Circuit	aggregate_score	Year
Oahu	[redacted]	[redacted]	37	5
Oahu			36	5
Oahu			36	5
Oahu			36	5
Oahu			36	5
Oahu			36	5
Oahu			35	5
Oahu			33	5
Oahu			33	5
Oahu			33	5
Oahu			32	5
Oahu			32	5
Oahu			32	5
Oahu			32	5
Oahu			31	5
Oahu			31	5
Oahu			30	5
Oahu			30	5
Oahu			30	5
Oahu			26	5
Oahu			24	5
Oahu			24	5

Hawaii – 39 circuits, 39 devices Primary SCADA Relay

Island	Substation	Circuit	aggregate_score	Year
Hawaii	[redacted]	[redacted]	65	1
Hawaii			55	2
Hawaii			55	2
Hawaii			55	2
Hawaii			55	2
Hawaii			55	2
Hawaii			55	2
Hawaii			55	2
Hawaii			55	2
Hawaii			55	2
Hawaii			55	2
Hawaii			55	2
Hawaii			54	2
Hawaii			54	2
Hawaii			53	2
Hawaii			53	2
Hawaii			53	2
Hawaii			53	2
Hawaii			52	2
Hawaii			52	2
Hawaii			52	2
Hawaii			52	2
Hawaii			52	2
Hawaii			51	2
Hawaii			51	2
Hawaii			50	3
Hawaii			50	3
Hawaii			50	3
Hawaii			48	3
Hawaii			45	4
Hawaii			45	4
Hawaii			45	4
Hawaii			45	4
Hawaii			44	4
Hawaii			44	4
Hawaii			43	4
Hawaii			42	4
Hawaii			40	5
Hawaii			40	5

Maui County – 14 circuits, 14 devices Primary SCADA Relay

Island	Substation	Circuit	aggregate_score	Year
Maui County	[redacted]	[redacted]	75	1
Maui County	[redacted]	[redacted]	70	1
Maui County	[redacted]	[redacted]	68	1
Maui County	[redacted]	[redacted]	67	1
Maui County	[redacted]	[redacted]	59	1
Maui County	[redacted]	[redacted]	57	1
Maui County	[redacted]	[redacted]	55	2
Maui County	[redacted]	[redacted]	51	2
Maui County	[redacted]	[redacted]	51	2
Maui County	[redacted]	[redacted]	46	3
Maui County	[redacted]	[redacted]	45	4
Maui County	[redacted]	[redacted]	40	5
Maui County	[redacted]	[redacted]	40	5
Maui County	[redacted]	[redacted]	40	5

Device: Primary Line Sensors

Total across all territories: Circuits: 24, Total devices: 24

Oahu – 19 circuits, 19 devices Primary Line Sensor

Island	Substation	Circuit	aggregate_score	Year
Oahu	[redacted]	[redacted]	75	1
Oahu			71	1
Oahu			71	1
Oahu			71	1
Oahu			68	1
Oahu			66	1
Oahu			66	1
Oahu			61	1
Oahu			60	1
Oahu			59	1
Oahu			59	1
Oahu			59	1
Oahu			59	1
Oahu			58	1
Oahu			57	1
Oahu			56	1
Oahu			55	1
Oahu			51	1
Oahu			44	1

Hawaii – 0 circuits, 0 devices Primary Line Sensor

Island	Substation	Circuit	aggregate_score	Year

Maui County – 5 circuits, 5 devices Primary Line Sensor

Island	Substation	Circuit	aggregate_score	Year
Maui County	[redacted]	[redacted]	75	1
Maui County	[redacted]	[redacted]	70	1
Maui County	[redacted]	[redacted]	68	1
Maui County	[redacted]	[redacted]	67	1
Maui County	[redacted]	[redacted]	57	1

Device: Secondary VAR Controllers

Total across all territories: Circuits: 57, Total devices: 1,425 (25 devices per circuit)

Oahu – 30 circuits, 750 devices Secondary VAR Controllers

Island	Substation	Circuit	aggregate_score	Number of devices	Year
Oahu	[redacted]	[redacted]	69	25	1
Oahu			66	25	1
Oahu			65	25	1
Oahu			51	25	2
Oahu			50	25	2
Oahu			50	25	2
Oahu			49	25	2
Oahu			48	25	3
Oahu			48	25	3
Oahu			48	25	3
Oahu			47	25	3
Oahu			47	25	3
Oahu			45	25	4
Oahu			45	25	4
Oahu			45	25	4
Oahu			45	25	4
Oahu			45	25	4
Oahu			45	25	4
Oahu			45	25	4
Oahu			45	25	4
Oahu			44	25	5
Oahu			44	25	5
Oahu			43	25	5
Oahu			43	25	5
Oahu			43	25	5
Oahu			43	25	5
Oahu			42	25	5
Oahu			42	25	5
Oahu			42	25	5
Oahu			42	25	5

Restricted

Maui County – 27 circuits, 675 devices Secondary VAR Controller

Island	Substation	Circuit	aggregate_score	Number of devices	Year
Maui County	[redacted]	[redacted]	47	25	3
Maui County			44	25	5
Maui County			46	25	3
Maui County			45	25	4
Maui County			43	25	5
Maui County			45	25	4
Maui County			41	25	5
Maui County			52	25	2
Maui County			68	25	1
Maui County			75	25	1
Maui County			68	25	1
Maui County			67	25	1
Maui County			78	25	1
Maui County			65	25	1
Maui County			50	25	2
Maui County			50	25	2
Maui County			53	25	1
Maui County			45	25	4
Maui County			48	25	3
Maui County			66	25	1
Maui County			47	25	3
Maui County			46	25	3
Maui County			47	25	3
Maui County			55	25	1
Maui County			51	25	2
Maui County			45	25	4
Maui County			50	25	2

Secondary Line Sensors

Total across all territories: Circuits: 532, Total devices: 4,788 (9 devices per circuit)

Oahu – 349 circuits, 3141 devices Secondary Line Sensor

Island	Substation	Circuit	aggregate_score	Number of devices	Year
Oahu	[redacted]	[redacted]	75	9	1
Oahu			72	9	1
Oahu			71	9	1
Oahu			71	9	1
Oahu			71	9	1
Oahu			71	9	1
Oahu			69	9	1
Oahu			69	9	1
Oahu			69	9	1
Oahu			69	9	1
Oahu			69	9	1
Oahu			69	9	1
Oahu			68	9	1
Oahu			68	9	1
Oahu			68	9	1
Oahu			67	9	1
Oahu			67	9	1
Oahu			66	9	1
Oahu			66	9	1
Oahu			65	9	1
Oahu			64	9	1
Oahu			64	9	1
Oahu			64	9	1
Oahu			64	9	1
Oahu			63	9	1
Oahu			63	9	1
Oahu			62	9	1
Oahu			62	9	1
Oahu			62	9	1
Oahu			61	9	1
Oahu			60	9	1
Oahu			60	9	1
Oahu			60	9	1
Oahu			60	9	1
Oahu			60	9	1
Oahu			60	9	1

Restricted

Island	Substation	Circuit	aggregate_score	Number of devices	Year
Oahu	[redacted]	[redacted]	59	9	1
Oahu	[redacted]	[redacted]	59	9	1
Oahu	[redacted]	[redacted]	59	9	1
Oahu	[redacted]	[redacted]	59	9	1
Oahu	[redacted]	[redacted]	59	9	1
Oahu	[redacted]	[redacted]	59	9	1
Oahu	[redacted]	[redacted]	59	9	1
Oahu	[redacted]	[redacted]	59	9	1
Oahu	[redacted]	[redacted]	59	9	1
Oahu	[redacted]	[redacted]	59	9	1
Oahu	[redacted]	[redacted]	59	9	1
Oahu	[redacted]	[redacted]	59	9	1
Oahu	[redacted]	[redacted]	59	9	1
Oahu	[redacted]	[redacted]	58	9	1
Oahu	[redacted]	[redacted]	58	9	1
Oahu	[redacted]	[redacted]	58	9	1
Oahu	[redacted]	[redacted]	57	9	1
Oahu	[redacted]	[redacted]	57	9	1
Oahu	[redacted]	[redacted]	57	9	1
Oahu	[redacted]	[redacted]	57	9	1
Oahu	[redacted]	[redacted]	57	9	1
Oahu	[redacted]	[redacted]	56	9	1
Oahu	[redacted]	[redacted]	56	9	1
Oahu	[redacted]	[redacted]	56	9	1
Oahu	[redacted]	[redacted]	55	9	1
Oahu	[redacted]	[redacted]	55	9	1
Oahu	[redacted]	[redacted]	55	9	1
Oahu	[redacted]	[redacted]	55	9	1
Oahu	[redacted]	[redacted]	55	9	1
Oahu	[redacted]	[redacted]	54	9	1
Oahu	[redacted]	[redacted]	54	9	1
Oahu	[redacted]	[redacted]	54	9	1
Oahu	[redacted]	[redacted]	54	9	1
Oahu	[redacted]	[redacted]	54	9	1
Oahu	[redacted]	[redacted]	53	9	2
Oahu	[redacted]	[redacted]	53	9	2
Oahu	[redacted]	[redacted]	53	9	2
Oahu	[redacted]	[redacted]	53	9	2
Oahu	[redacted]	[redacted]	53	9	2
Oahu	[redacted]	[redacted]	53	9	2
Oahu	[redacted]	[redacted]	52	9	2

Restricted

Island	Substation	Circuit	aggregate_score	Number of devices	Year
Oahu	[redacted]	[redacted]	52	9	2
Oahu	[redacted]	[redacted]	52	9	2
Oahu	[redacted]	[redacted]	52	9	2
Oahu	[redacted]	[redacted]	52	9	2
Oahu	[redacted]	[redacted]	52	9	2
Oahu	[redacted]	[redacted]	52	9	2
Oahu	[redacted]	[redacted]	52	9	2
Oahu	[redacted]	[redacted]	52	9	2
Oahu	[redacted]	[redacted]	52	9	2
Oahu	[redacted]	[redacted]	51	9	2
Oahu	[redacted]	[redacted]	51	9	2
Oahu	[redacted]	[redacted]	51	9	2
Oahu	[redacted]	[redacted]	51	9	2
Oahu	[redacted]	[redacted]	51	9	2
Oahu	[redacted]	[redacted]	51	9	2
Oahu	[redacted]	[redacted]	51	9	2
Oahu	[redacted]	[redacted]	51	9	2
Oahu	[redacted]	[redacted]	51	9	2
Oahu	[redacted]	[redacted]	51	9	2
Oahu	[redacted]	[redacted]	51	9	2
Oahu	[redacted]	[redacted]	50	9	2
Oahu	[redacted]	[redacted]	50	9	2
Oahu	[redacted]	[redacted]	50	9	2
Oahu	[redacted]	[redacted]	50	9	2
Oahu	[redacted]	[redacted]	49	9	2
Oahu	[redacted]	[redacted]	49	9	2
Oahu	[redacted]	[redacted]	49	9	2
Oahu	[redacted]	[redacted]	49	9	2
Oahu	[redacted]	[redacted]	49	9	2
Oahu	[redacted]	[redacted]	48	9	2
Oahu	[redacted]	[redacted]	48	9	2
Oahu	[redacted]	[redacted]	48	9	2
Oahu	[redacted]	[redacted]	48	9	2
Oahu	[redacted]	[redacted]	48	9	2
Oahu	[redacted]	[redacted]	48	9	2
Oahu	[redacted]	[redacted]	48	9	2
Oahu	[redacted]	[redacted]	48	9	2
Oahu	[redacted]	[redacted]	48	9	2
Oahu	[redacted]	[redacted]	48	9	2
Oahu	[redacted]	[redacted]	48	9	2
Oahu	[redacted]	[redacted]	48	9	2

Restricted

Island	Substation	Circuit	aggregate_score	Number of devices	Year
Oahu	[redacted]	[redacted]	47	9	2
Oahu			47	9	2
Oahu			47	9	2
Oahu			47	9	2
Oahu			47	9	2
Oahu			47	9	2
Oahu			47	9	2
Oahu			47	9	2
Oahu			47	9	2
Oahu			47	9	2
Oahu			47	9	2
Oahu			47	9	2
Oahu			47	9	2
Oahu			47	9	2
Oahu			46	9	3
Oahu			46	9	3
Oahu			46	9	3
Oahu			46	9	3
Oahu			46	9	3
Oahu			46	9	3
Oahu			46	9	3
Oahu			46	9	3
Oahu			46	9	3
Oahu			46	9	3
Oahu			45	9	3
Oahu			45	9	3
Oahu			45	9	3
Oahu			45	9	3
Oahu			45	9	3
Oahu			45	9	3
Oahu			45	9	3
Oahu			45	9	3
Oahu			45	9	3
Oahu			45	9	3
Oahu			44	9	3
Oahu			44	9	3
Oahu			44	9	3
Oahu			44	9	3
Oahu			44	9	3
Oahu			44	9	3
Oahu			44	9	3

Restricted

Island	Substation	Circuit	aggregate_score	Number of devices	Year
Oahu	[redacted]	[redacted]	44	9	3
Oahu			44	9	3
Oahu			43	9	3
Oahu			43	9	3
Oahu			43	9	3
Oahu			43	9	3
Oahu			43	9	3
Oahu			43	9	3
Oahu			42	9	3
Oahu			42	9	3
Oahu			42	9	3
Oahu			42	9	3
Oahu			42	9	3
Oahu			42	9	3
Oahu			42	9	3
Oahu			42	9	3
Oahu			42	9	3
Oahu			42	9	3
Oahu			42	9	3
Oahu			42	9	3
Oahu			42	9	3
Oahu			42	9	3
Oahu			42	9	3
Oahu			42	9	3
Oahu			41	9	3
Oahu			41	9	3
Oahu			41	9	3
Oahu			41	9	3
Oahu			41	9	3
Oahu			41	9	3
Oahu			41	9	3
Oahu			41	9	3
Oahu			41	9	3
Oahu			40	9	4
Oahu			40	9	4
Oahu			40	9	4
Oahu			40	9	4
Oahu			40	9	4
Oahu			40	9	4
Oahu			40	9	4
Oahu			40	9	4

Restricted

Island	Substation	Circuit	aggregate_score	Number of devices	Year
Oahu	[redacted]	[redacted]	40	9	4
Oahu			40	9	4
Oahu			40	9	4
Oahu			40	9	4
Oahu			40	9	4
Oahu			40	9	4
Oahu			39	9	4
Oahu			39	9	4
Oahu			39	9	4
Oahu			39	9	4
Oahu			39	9	4
Oahu			39	9	4
Oahu			39	9	4
Oahu			39	9	4
Oahu			39	9	4
Oahu			39	9	4
Oahu			39	9	4
Oahu			39	9	4
Oahu			39	9	4
Oahu			39	9	4
Oahu			38	9	4
Oahu			38	9	4
Oahu			38	9	4
Oahu			38	9	4
Oahu			38	9	4
Oahu			38	9	4
Oahu			38	9	4
Oahu			38	9	4
Oahu			38	9	4
Oahu			38	9	4
Oahu			38	9	4
Oahu			38	9	4
Oahu			38	9	4
Oahu			38	9	4
Oahu			38	9	4
Oahu			38	9	4
Oahu			38	9	4
Oahu			37	9	4
Oahu			37	9	4
Oahu			37	9	4
Oahu			37	9	4

Restricted

Island	Substation	Circuit	aggregate_score	Number of devices	Year
Oahu	[redacted]	[redacted]	37	9	4
Oahu	[redacted]	[redacted]	37	9	4
Oahu	[redacted]	[redacted]	37	9	4
Oahu	[redacted]	[redacted]	37	9	4
Oahu	[redacted]	[redacted]	36	9	5
Oahu	[redacted]	[redacted]	36	9	5
Oahu	[redacted]	[redacted]	36	9	5
Oahu	[redacted]	[redacted]	36	9	5
Oahu	[redacted]	[redacted]	36	9	5
Oahu	[redacted]	[redacted]	36	9	5
Oahu	[redacted]	[redacted]	36	9	5
Oahu	[redacted]	[redacted]	36	9	5
Oahu	[redacted]	[redacted]	36	9	5
Oahu	[redacted]	[redacted]	36	9	5
Oahu	[redacted]	[redacted]	36	9	5
Oahu	[redacted]	[redacted]	36	9	5
Oahu	[redacted]	[redacted]	36	9	5
Oahu	[redacted]	[redacted]	36	9	5
Oahu	[redacted]	[redacted]	36	9	5
Oahu	[redacted]	[redacted]	36	9	5
Oahu	[redacted]	[redacted]	36	9	5
Oahu	[redacted]	[redacted]	35	9	5
Oahu	[redacted]	[redacted]	35	9	5
Oahu	[redacted]	[redacted]	35	9	5
Oahu	[redacted]	[redacted]	35	9	5
Oahu	[redacted]	[redacted]	35	9	5
Oahu	[redacted]	[redacted]	35	9	5
Oahu	[redacted]	[redacted]	35	9	5
Oahu	[redacted]	[redacted]	35	9	5
Oahu	[redacted]	[redacted]	35	9	5
Oahu	[redacted]	[redacted]	35	9	5
Oahu	[redacted]	[redacted]	34	9	5
Oahu	[redacted]	[redacted]	34	9	5
Oahu	[redacted]	[redacted]	34	9	5
Oahu	[redacted]	[redacted]	34	9	5
Oahu	[redacted]	[redacted]	34	9	5
Oahu	[redacted]	[redacted]	33	9	5
Oahu	[redacted]	[redacted]	33	9	5
Oahu	[redacted]	[redacted]	33	9	5
Oahu	[redacted]	[redacted]	33	9	5

Restricted

Island	Substation	Circuit	aggregate_score	Number of devices	Year
Oahu	[redacted]	[redacted]	33	9	5
Oahu			33	9	5
Oahu			33	9	5
Oahu			33	9	5
Oahu			33	9	5
Oahu			33	9	5
Oahu			33	9	5
Oahu			33	9	5
Oahu			32	9	5
Oahu			32	9	5
Oahu			32	9	5
Oahu			32	9	5
Oahu			32	9	5
Oahu			32	9	5
Oahu			32	9	5
Oahu			32	9	5
Oahu			32	9	5
Oahu			32	9	5
Oahu			32	9	5
Oahu			31	9	5
Oahu			31	9	5
Oahu			31	9	5
Oahu			31	9	5
Oahu			31	9	5
Oahu			31	9	5
Oahu			31	9	5
Oahu			31	9	5
Oahu			31	9	5
Oahu			31	9	5
Oahu			30	9	5
Oahu			30	9	5
Oahu			30	9	5
Oahu			30	9	5
Oahu			30	9	5
Oahu			30	9	5
Oahu			29	9	5
Oahu			29	9	5
Oahu			29	9	5
Oahu			29	9	5
Oahu			29	9	5
Oahu			29	9	5

Restricted

Island	Substation	Circuit	aggregate_score	Number of devices	Year
Oahu	[redacted]	[redacted]	29	9	5
Oahu			28	9	5
Oahu			28	9	5
Oahu			28	9	5
Oahu			28	9	5
Oahu			28	9	5
Oahu			28	9	5
Oahu			28	9	5
Oahu			27	9	5
Oahu			27	9	5
Oahu			27	9	5
Oahu			27	9	5
Oahu			26	9	5
Oahu			26	9	5
Oahu			26	9	5
Oahu			26	9	5
Oahu			25	9	5
Oahu			24	9	5
Oahu			24	9	5
Oahu			24	9	5
Oahu			24	9	5
Oahu			22	9	5
Oahu			21	9	5
Oahu			20	9	5
Oahu			18	9	5
Oahu			18	9	5
Oahu			18	9	5

Hawaii – 122 circuits, 1098 devices Secondary Line Sensor

Island	Substation	Circuit	Aggregate score	Number of devices	Year
Hawaii	[redacted]	[redacted]	65	9	1
Hawaii	[redacted]	[redacted]	64	9	1
Hawaii	[redacted]	[redacted]	60	9	1
Hawaii	[redacted]	[redacted]	55	9	1
Hawaii	[redacted]	[redacted]	55	9	1
Hawaii	[redacted]	[redacted]	55	9	1
Hawaii	[redacted]	[redacted]	55	9	1
Hawaii	[redacted]	[redacted]	55	9	1
Hawaii	[redacted]	[redacted]	55	9	1
Hawaii	[redacted]	[redacted]	55	9	1
Hawaii	[redacted]	[redacted]	55	9	1
Hawaii	[redacted]	[redacted]	55	9	1
Hawaii	[redacted]	[redacted]	55	9	1
Hawaii	[redacted]	[redacted]	55	9	1
Hawaii	[redacted]	[redacted]	55	9	1
Hawaii	[redacted]	[redacted]	54	9	1
Hawaii	[redacted]	[redacted]	54	9	1
Hawaii	[redacted]	[redacted]	54	9	1
Hawaii	[redacted]	[redacted]	53	9	2
Hawaii	[redacted]	[redacted]	53	9	2
Hawaii	[redacted]	[redacted]	53	9	2
Hawaii	[redacted]	[redacted]	53	9	2
Hawaii	[redacted]	[redacted]	52	9	2
Hawaii	[redacted]	[redacted]	52	9	2
Hawaii	[redacted]	[redacted]	52	9	2
Hawaii	[redacted]	[redacted]	52	9	2
Hawaii	[redacted]	[redacted]	52	9	2
Hawaii	[redacted]	[redacted]	51	9	2
Hawaii	[redacted]	[redacted]	51	9	2
Hawaii	[redacted]	[redacted]	51	9	2
Hawaii	[redacted]	[redacted]	51	9	2
Hawaii	[redacted]	[redacted]	51	9	2
Hawaii	[redacted]	[redacted]	51	9	2
Hawaii	[redacted]	[redacted]	51	9	2
Hawaii	[redacted]	[redacted]	50	9	2
Hawaii	[redacted]	[redacted]	50	9	2
Hawaii	[redacted]	[redacted]	50	9	2
Hawaii	[redacted]	[redacted]	50	9	2
Hawaii	[redacted]	[redacted]	50	9	2
Hawaii	[redacted]	[redacted]	50	9	2

Restricted[redacted]

Island	Substation	Circuit	Aggregate score	Number of devices	Year
Hawaii	[redacted]	[redacted]	50	9	2
Hawaii	[redacted]	[redacted]	50	9	2
Hawaii	[redacted]	[redacted]	50	9	2
Hawaii	[redacted]	[redacted]	50	9	2
Hawaii	[redacted]	[redacted]	50	9	2
Hawaii	[redacted]	[redacted]	48	9	2
Hawaii	[redacted]	[redacted]	48	9	2
Hawaii	[redacted]	[redacted]	48	9	2
Hawaii	[redacted]	[redacted]	47	9	2
Hawaii	[redacted]	[redacted]	47	9	2
Hawaii	[redacted]	[redacted]	46	9	3
Hawaii	[redacted]	[redacted]	46	9	3
Hawaii	[redacted]	[redacted]	46	9	3
Hawaii	[redacted]	[redacted]	46	9	3
Hawaii	[redacted]	[redacted]	46	9	3
Hawaii	[redacted]	[redacted]	46	9	3
Hawaii	[redacted]	[redacted]	46	9	3
Hawaii	[redacted]	[redacted]	46	9	3
Hawaii	[redacted]	[redacted]	46	9	3
Hawaii	[redacted]	[redacted]	46	9	3
Hawaii	[redacted]	[redacted]	46	9	3
Hawaii	[redacted]	[redacted]	46	9	3
Hawaii	[redacted]	[redacted]	46	9	3
Hawaii	[redacted]	[redacted]	46	9	3
Hawaii	[redacted]	[redacted]	46	9	3
Hawaii	[redacted]	[redacted]	45	9	3
Hawaii	[redacted]	[redacted]	45	9	3
Hawaii	[redacted]	[redacted]	45	9	3
Hawaii	[redacted]	[redacted]	45	9	3
Hawaii	[redacted]	[redacted]	45	9	3
Hawaii	[redacted]	[redacted]	45	9	3
Hawaii	[redacted]	[redacted]	45	9	3
Hawaii	[redacted]	[redacted]	45	9	3
Hawaii	[redacted]	[redacted]	45	9	3
Hawaii	[redacted]	[redacted]	44	9	3
Hawaii	[redacted]	[redacted]	43	9	3
Hawaii	[redacted]	[redacted]	42	9	3
Hawaii	[redacted]	[redacted]	42	9	3
Hawaii	[redacted]	[redacted]	42	9	3
Hawaii	[redacted]	[redacted]	42	9	3
Hawaii	[redacted]	[redacted]	42	9	3

Restricte [redacted]

Island	Substation	Circuit	Aggregate score	Number of devices	Year
Hawaii	[redacted]	[redacted]	41	9	3
Hawaii			41	9	3
Hawaii			40	9	4
Hawaii			40	9	4
Hawaii			40	9	4
Hawaii			40	9	4
Hawaii			40	9	4
Hawaii			40	9	4
Hawaii			40	9	4
Hawaii			40	9	4
Hawaii			40	9	4
Hawaii			39	9	4
Hawaii			39	9	4
Hawaii			39	9	4
Hawaii			38	9	4
Hawaii			38	9	4
Hawaii			38	9	4
Hawaii			36	9	5
Hawaii			36	9	5
Hawaii			36	9	5
Hawaii			36	9	5
Hawaii			36	9	5
Hawaii			36	9	5
Hawaii			36	9	5
Hawaii			36	9	5
Hawaii			36	9	5
Hawaii			36	9	5
Hawaii			36	9	5
Hawaii			36	9	5
Hawaii			36	9	5
Hawaii			35	9	5
Hawaii			34	9	5
Hawaii			33	9	5
Hawaii			32	9	5
Hawaii			31	9	5
Hawaii			31	9	5
Hawaii			31	9	5
Hawaii			31	9	5
Hawaii			31	9	5
Hawaii			31	9	5
Hawaii			30	9	5

Restricted [redacted]

Maui County – 61 circuits, 549 devices Secondary Line Sensor

Island	Substation	Circuit	aggregate_score	Number of devices	Year
Maui County	[redacted]		70	9	1
Maui County			68	9	1
Maui County			68	9	1
Maui County			68	9	1
Maui County			67	9	1
Maui County			66	9	1
Maui County			65	9	1
Maui County			62	9	1
Maui County			60	9	1
Maui County			57	9	1
Maui County			57	9	1
Maui County			56	9	1
Maui County			50	9	2
Maui County			50	9	2
Maui County			50	9	2
Maui County			48	9	2
Maui County			48	9	2
Maui County			48	9	2
Maui County			47	9	2
Maui County			47	9	2
Maui County			46	9	3
Maui County			46	9	3
Maui County			46	9	3
Maui County			46	9	3
Maui County			46	9	3
Maui County			46	9	3
Maui County			45	9	3
Maui County			45	9	3
Maui County			43	9	3
Maui County			41	9	3
Maui County			41	9	3
Maui County			41	9	3
Maui County			40	9	4
Maui County			40	9	4
Maui County			40	9	4
Maui County			40	9	4
Maui County			40	9	4
Maui County			40	9	4
Maui County			40	9	4
Maui County			40	9	4
Maui County			40	9	4

Restricted

Island	Substation	Circuit	aggregate_score	Number of devices	Year
Maui County	[redacted]		40	9	4
Maui County			40	9	4
Maui County			40	9	4
Maui County			40	9	4
Maui County			40	9	4
Maui County			38	9	4
Maui County			38	9	4
Maui County			37	9	4
Maui County			37	9	4
Maui County			36	9	5
Maui County			36	9	5
Maui County			36	9	5
Maui County			36	9	5
Maui County			36	9	5
Maui County			36	9	5
Maui County			35	9	5
Maui County			35	9	5
Maui County			33	9	5
Maui County			30	9	5
Maui County			30	9	5

Exhibit L

Grid Modernization Strategy Phase 2 ADMS and Field Device 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
Application pages 4, 5, 52, and 53	The Companies' estimated costs associated with the procurement and deployment of ADMS and Field Device components of Phase 2 of the Grid Modernization Strategy.	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 proposals and negotiations; impact the Company's bargaining power relative to its vendors; harm the Company's relationship with existing and/or prospective vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers. In addition, Public disclosure of the confidential information could place the Company's vendors at a competitive disadvantage with respect to industry competitors; may discourage vendors from doing business with the Company; may discourage vendors from making confidential disclosures to the Company; and may expose the Company to certain liabilities.

[1] Haw. Rev. Stat. § 92F-13(3).

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit B, pages 40-46	The Companies' estimated costs associated with the procurement and deployment of ADMS and Field Device components of Phase 2 of the Grid Modernization Strategy.	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 proposals and negotiations; impact the Company's bargaining power relative to its vendors; harm the Company's relationship with existing and/or prospective vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers. In addition, Public disclosure of the confidential information could place the Company's vendors at a competitive disadvantage with respect to industry competitors; may discourage vendors from doing business with the Company; may discourage vendors from making confidential disclosures to the Company; and may expose the Company to certain liabilities. Further, public disclosure of the confidential information would provide a roadmap, enabling competitors to not provide their best price in response to subsequent RFP's, but rather a price at or slightly below what is offered by Company. The Company contends that disclosure of the information will not only harm the Company competitively but could also have an adverse impact on subsequent RFPs.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit C, page 4	Vendor pricing information.	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 proposals and negotiations; impact the Company's bargaining power relative to its vendors; harm the Company's relationship with existing and/or prospective vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers. In addition, Public disclosure of the confidential information could place the Company's vendors at a competitive disadvantage with respect to industry competitors; may discourage vendors from doing business with the Company; may discourage vendors from making confidential disclosures to the Company; and may expose the Company to certain liabilities.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit D, pages 2,8,11, and 13 - 15	The Companies' estimated costs associated with the procurement and deployment of ADMS and Field Device components of Phase 2 of the Grid Modernization Strategy.	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 proposals and negotiations; impact the Company's bargaining power relative to its vendors; harm the Company's relationship with existing and/or prospective vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers. In addition, Public disclosure of the confidential information could place the Company's vendors at a competitive disadvantage with respect to industry competitors; may discourage vendors from doing business with the Company; may discourage vendors from making confidential disclosures to the Company; and may expose the Company to certain liabilities.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit E, pages 8 and 9	The Companies' Request For Proposal scoring criteria and results associated with the procurement and deployment of the ADMS.	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 proposals and negotiations; impact the Company's bargaining power relative to its vendors; harm the Company's relationship with existing and/or prospective vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers. In addition, Public disclosure of the confidential information could place the Company's vendors at a competitive disadvantage with respect to industry competitors; may discourage vendors from doing business with the Company; may discourage vendors from making confidential disclosures to the Company; and may expose the Company to certain liabilities.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit E, Attachments 1	The Companies' Request For Proposal documents associated with the procurement and deployment of the ADMS.	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 proposals and negotiations; impact the Company's bargaining power relative to its vendors; harm the Company's relationship with existing and/or prospective 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 G, pages 1-6	The Companies' estimated costs associated with the procurement and deployment of ADMS and Field Device components of Phase 2 of the Grid Modernization Strategy.	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 proposals and negotiations; impact the Company's bargaining power relative to its vendors; harm the Company's relationship with existing and/or prospective vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers. In addition, Public disclosure of the confidential information could place the Company's vendors at a competitive disadvantage with respect to industry competitors; may discourage vendors from doing business with the Company; may discourage vendors from making confidential disclosures to the Company; and may expose the Company to certain liabilities. Further, public disclosure of the confidential information would provide a roadmap, enabling competitors to not provide their best price in response to subsequent RFP's, but rather a price at or slightly below what is offered by Company. The Company contends that disclosure of the information will not only harm the Company competitively, but could also have an adverse impact on subsequent RFPs.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit H, pages 3,4,6-8, and 11-13	The Companies' estimated costs associated with the procurement and deployment of ADMS and Field Device components of Phase 2 of the Grid Modernization Strategy.	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 proposals and negotiations; impact the Company's bargaining power relative to its vendors; harm the Company's relationship with existing and/or prospective vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers. In addition, Public disclosure of the confidential information could place the Company's vendors at a competitive disadvantage with respect to industry competitors; may discourage vendors from doing business with the Company; may discourage vendors from making confidential disclosures to the Company; and may expose the Company to certain liabilities.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit I, pages 1-10	The Companies' estimated costs and revenue requirements associated with the procurement and deployment of components within the Grid Modernization Phase 2 ADMS.	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 proposals and negotiations; impact the Company's bargaining power relative to its vendors; harm the Company's relationship with existing and/or prospective vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers. In addition, Public disclosure of the confidential information could place the Company's vendors at a competitive disadvantage with respect to industry competitors; may discourage vendors from doing business with the Company; may discourage vendors from making confidential disclosures to the Company; and may expose the Company to certain liabilities.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit K, pages 57, 60, 81-87, 89-105	Field Device deployment recommendations based on a detailed analysis of the Companies substation and circuits.	To the extent that the confidential information consists of critical infrastructure information that should not be disclosed under the Homeland Security Act of 2002, such information is exempt from disclosure under the section 92F-13(4) of the UIPA	Public disclosure of this information could increase risk to the Company's facilities, jeopardize its emergency and disaster preparedness plans, and/or adversely impact its ability to respond to potential terrorist threats.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAIʻI

In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC. HAWAIʻI ELECTRIC LIGHT COMPANY, INC. MAUI ELECTRIC COMPANY, LIMITED dba HAWAIIAN ELECTRIC For approval to commit funds in excess of $2,500,000 for the Field Device Component of the Phase 2 Grid Modernization Project, to Defer Certain Computer Software Development Costs, to Recover the Capital, Deferred, and the Operations and Expense Costs through the Exceptional Project Recovery Mechanism, and Related Requests.	)	DOCKET NO. 2019-0327

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Supplement, together with this Certificate of Service, was duly served on the following party, by electronic mail service as set forth below:[54]

Division of Consumer Advocacy
Department of Commerce and Consumer Affairs
335 Merchant Street, Room 326
Honolulu, Hawaiʻi 96813
dnishina@dcca.hawaii.gov
consumeradvocate@dcca.hawaii.gov

DATED: Honolulu, Hawaiʻi March 31, 2021

/s/ Richard VanDrunen

Richard VanDrunen
HAWAIIAN ELECTRIC COMPANY, INC.
Regulatory Affairs

[54] As stated in Order No. 37043 *Setting Forth Public Utilities Commission Emergency Filing and Service Procedures related to COVID-19* (non-docketed), issued on March 13, 2020 at 11: Service of all documents filed by any parties, participants, utilities, stakeholders and/or other entities or individuals shall be via email.