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. and MAUI ELECTRIC COMPANY, LIMITED For approval to commit funds in excess of $2,500,000 for the Smart Grid Foundation Project, to Defer Certain Computer Software Development Costs, to Recover the Capital and Deferred Costs through the Renewable Energy Infrastructure Surcharge, and Related Requests.	)	Docket No.

APPLICATION OF
HAWAIIAN ELECTRIC COMPANY, INC.,
HAWAIʻI ELECTRIC LIGHT COMPANY INC. and
MAUI ELECTRIC COMPANY, LIMITED

EXHIBITS A - I

VERIFICATION

and

CERTIFICATE OF SERVICE

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	)	
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to Defer Certain Computer Software Development	)	
Costs, to Recover the Capital and Deferred Costs	)	
through the Renewable Energy Infrastructure	)	
Surcharge, and Related Requests.	)	
	)	

APPLICATION

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

Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Hawaiʻi Electric Light Company, Inc. ("Hawaiʻi Electric Light") and Maui Electric Company, Limited ("Maui Electric") (collectively the "Hawaiian Electric Companies" or "Companies") respectfully submit this Application in support of their Smart Grid Foundation Project ("SGF Project").

I. INTRODUCTION/EXECUTIVE SUMMARY

The SGF Project is essential to the State's energy future and the Hawaiian Electric Companies' transformation into a more customer-oriented, flexible clean energy provider. The establishment of a more dynamic and secure power grid that gives customers more control, greater flexibility and more choices, responds to outages more quickly, seamlessly connects with cleaner energy resources, and better secures the grid from attacks ("Smart Grid") is a necessary step in order to achieve the State of Hawai'i's first-in-the-nation renewable portfolio standards ("RPS") goal of 100% renewable energy by 2045. The success of Hawai'i's Smart Grid will require a collaborative effort by all stakeholders, including the utilities, regulators, government entities, business and community groups, and electric customers.

Building a Smart Grid in Hawai'i will not be accomplished in a single project, but will evolve over time, by growing and layering capabilities that deliver additional value to customers. The purpose of the SGF Project is to implement the initial Smart Grid capabilities that will serve as the platform to support not only immediate customer benefits, but also as the cornerstone for additional projects (separate and apart from the SGF Project) that can expand customer options, such as optimizing the integration of distributed energy resources ("DER"), implementing demand response ("DR"), time-of-use ("TOU") rates and real-time-pricing ("RTP"), and increasing reliability through distribution automation ("DA"). As delineated in the Companies' Smart Grid Strategy and Roadmap ("Smart Grid Roadmap"),[1] these additional initiatives will be phased-in over the next several years through separate pending (e.g., DR Portfolio, DER TOU) and follow-on (e.g., DA Project, RTP Tariff) applications. When taken in their entirety, the overall bundle of benefits and capabilities set forth in the Smart Grid Roadmap supports an overall positive business case over the next 20 years.

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[1] <u>See</u> Exhibit A at 26, Figure 9 (Near Term Smart Grid Related PUC Filings).

The SGF Project will enable foundational Smart Grid capabilities in five key strategic areas:

(1) *Customer empowerment* capabilities that that allow customers to monitor their energy use patterns and make informed adjustments that can reduce their consumption and lower energy expenses, as well as enabling a more convenient means to participate in money saving rate options such as TOU rates;

(2) *DER integration* capabilities that will allow more customers to have DER sooner, as a result of smart meters providing increased visibility into a power grid that efficiently delivers reliable and safe energy to customers;

(3) *Grid efficiency, reliability and resiliency* capabilities that will use smart meters as sensors to automatically detect power outages and enable faster restoration of power, as well as enable the Companies to burn less fuel to meet customer demand for energy;

(4) *Safety and workforce efficiency* improvements enabled by remote capabilities that enable better detection of energy theft and also eliminate the need for the Companies' personnel to enter customer premises, which means fewer accidents, faster service connections, more accurate billing and fewer interruptions for customers; and

(5) *Innovation, information and connectivity* that will make it easier for new smart technologies (as developed) and customer-sited generation to build a smarter energy infrastructure that delivers the benefits of new technologies to

customers and leverages them for many uses, while proactively keeping customer data safe, private and secure.

The SGF Project will consist of ten interrelated components:

- Eight subprojects, the scopes of which have been tailored based on a "best-fit/least-cost" approach that utilizes commercially available and proven cost-effective technologies to deliver the key foundational Smart Grid capabilities and immediate value and benefits to customers, including:
  - Installation of *Advanced Metering Infrastructure* ("AMI") to provide two-way communications and control between the Companies and the installed smart meters that support the innovation, information and connectivity capabilities of the Smart Grid;
  - Creation of a *Customer Facing Solution* ("CFS") that uses information from smart meters, provided through online and mobile pathways, to give customers more information and control over how they use their energy, while improving the customer experience;
  - Implementation of *Conservation Voltage Reduction* ("CVR") technologies that support the grid efficiency, reliability and resiliency capabilities by using voltage measurements from the smart meters to enable the Companies to improve efficiencies and burn less fuel to generate energy to meet demand;
  - A *Direct Load Control* ("DLC") subproject to upgrade existing DLC switches on O‘ahu to improve monitoring and control of participating customers' water heater operations and stabilize the power grid during peak demand, in support of the DER integration capabilities;

- Development of an *Enterprise Data Warehouse* ("EDW") to serve as the central repository of the large amounts of data gathered over the AMI network and other company data used to improve electric service to customers;
- Enhancement of the Companies' existing *Enterprise Service Bus* ("ESB") to enable seamless flow of data through the Companies' various computer systems, also in support of the innovation, information and connectivity capabilities of the Smart Grid;
- Implementation of a *Meter Data Management System* ("MDMS") that will capture and manage the customer interval energy usage data obtained from the smart meters to enable automated billing and operational efficiencies such as reduced truck rolls from eliminated manual meter reads; and
- Expansion of Hawaiian Electric's *Outage Management System* ("OMS") on O'ahu to Maui Electric and Hawai'i Electric Light in order to improve outage communications, and increase the speed and efficiency of power restoration;

- A ninth component for *Customer Engagement* ("CE") activities to help customers maximize the benefits of the new Smart Grid technologies and support the eight subprojects listed above; and
- A tenth component for *Project Management Office* ("PMO") services that also support the eight subprojects above, as well as the CE activities, in order to ensure smooth, cost-effective and coordinated project execution.

The SGF Project is scheduled to commence in early 2017 upon a decision and order enabling the project to commence, and is expected to take five years to complete. Over the course of the implementation, the Companies will continue to emphasize and carry out focused customer engagement activities similar to those conducted during their Smart Grid initial phase demonstration project on O‘ahu (“Initial Phase”), building upon the lessons learned from those activities to help customers maximize the capabilities of the newly enabled technologies and options. The Companies will also continue to reassess and update their data privacy policies and cybersecurity solutions in order to address the complexities that the new applications, network access points and data add to their enterprise systems.

In general, the customer benefits of the SGF Project fall into the following three categories: (1) “Operational Benefits” that benefit customers by reducing the revenue requirements used to set base rates; (2) “Direct Customer Benefits” that inure directly to customers, such as through adjustments in their energy use patterns that reduce consumption, as well as through energy cost or other adjustment clause mechanisms; and (3) other benefits that cannot be readily quantified at this time (“Non-Quantified Benefits”). The benefits attributable to the AMI subproject (including benefits related to the MDMS, ESB and EDW subprojects), portions of the OMS subproject (i.e., related to outage operational efficiency) and the internal incremental labor offset are considered to be Operational Benefits, and are estimated at approximately $294 million over the expected 20-year project life (i.e., from 2017 to 2036). The benefits attributable to the CFS, CVR and DLC subprojects, as well as other portions of the OMS subproject (i.e., related to value of service)[2] are considered to be Direct Customer Benefits, and are estimated at approximately $584 million over the 20-year project life. The sum of the Operational Benefits and Direct Customer Benefits is approximately $878 million in nominal

[2] The value of service benefit is based on the cost of electric service interruption to a customer (e.g., loss of revenue, loss of materials/inventory due to interruption of refrigeration, etc.)

dollars. The present value of these benefits over the 20-year life of the SGF Project investment is approximately $345 million.

As summarized in Table 1 below, the total estimated cost of the SGF Project over its five-year implementation period (i.e., the costs for which the Companies are seeking recovery in the accompanying Application) is approximately $340 million. Included in this $340 million cost estimate are approximately $206 million of capital costs, $75 million of deferred costs and $59 million of incremental expense items.

SGF Project Implementation Costs (2017-2021)	
Cost Component	Nominal ($millions)
AMI Subproject	180
CFS Subproject	9
CVR Subproject	26
DLC Subproject	18
EDW Subproject	10
ESB Subproject	10
MDMS Subproject	50
OMS Subproject	18
CE	8
PMO	11
Total	**340**

Table 1

In addition to the $340 million of SGF Project implementation costs listed above, after the various releases of the subprojects are placed in service, the Companies anticipate that $345 million in additional costs will need to be incurred in order to support and maintain the investment over its life ("ongoing costs"). Another $51 million of expense will be incurred in connection with the Companies' proposal to amortize the remaining book value of the existing non-AMI meters over a ten-year period ("non-AMI meter amortization"). The sum of the SGF Project implementation costs, on-going costs and non-AMI meter amortization is approximately

$736 million in nominal dollars. The present value of these costs over the 20-year life of the SGF Project investment is approximately $413 million.

In order to evaluate the overall financial impact of the SGF Project on a typical residential customer, the Companies have performed an "economic analysis" that nets the twenty-year SGF Project costs and ongoing costs against the Operational Benefits and Direct Customer Benefits, taking into account the time-value of money, as shown in Table 2 below.

Present Value of 20-Year SGF Project & Ongoing Costs and Benefits		
Smart Grid Capability	Project & Ongoing Costs ($ millions)	Benefits ($ millions)
Automated meter reading, TOU support, interval billing, remote connect/disconnect, enable RTP	314	116
Improved customer experience, options and access	12	54
Enhanced EnergyScout water heater DLC program	14	10
Energy efficiency via CVR	36	151
Enhanced outage management and automation extension to Maui Electric and Hawai'i Electric Light	30	7
Internal incremental labor offset	7	7
Total	**413**	**345**
Benefit-to-Cost Ratio ("BCR")	**0.84**	

Table 2

Although the overall bundle of benefits and capabilities of the larger spectrum of Smart Grid capabilities detailed in the Smart Grid Roadmap supports an overall positive business case, the SGF Project viewed in isolation has a BCR of 0.84. However, there are a number of benefits of the SGF Project that cannot be readily quantified at this time, but which add to its value proposition, including but not limited to:

- customer satisfaction improvements;
- increased data visibility to improve hosting capacity models for DER;
- environmental benefits from decreased reliance on imported fuel;
- economic growth in the local renewable energy industry; and

- reduced carbon footprint via a reduction of greenhouse gas ("GHG") emissions by making the distribution and use of power more efficient.

In addition, the BCR does not consider the positive impact of the future opportunities to increase functionality, flexible system capabilities, and expansion of customer options provided by the SGF Project. For example, it is not possible to offer RTP without the MDMS solution that is connected to an installed base of smart meters. Moreover, the Smart Grid network also delivers enhanced value to existing DR programs by providing near-real-time communications and usage information to customers and the utility. Other near-term initiatives also will build on the capabilities enabled by the SGF Project. Thus, the SGF Project is one of the cornerstones that will enable Hawai‘i to achieve the 100% RPS by 2045.

The typical monthly difference in costs to residential customers due to the investment (i.e., taking into account SGF Project costs and on-going costs, Operational Benefits and Direct Customer Benefits) over the 20-year life of the investment will range between 20 to 35 cents, depending on factors unique to the Companies' different service territories. This is projected to peak in 2022 for the typical residential customer at approximately $1.70/month for Hawaiian Electric and Maui Electric, and in 2020 at approximately $2.39/month for Hawai‘i Electric Light. By the 2029-2030 timeframe, the typical monthly difference in costs to the customer will begin to result in net savings, peaking at approximately -$1.59 for Hawaiian Electric, -$1.15 for Maui Electric and -$2.35 at Hawai‘i Electric Light.

The accounting for the various SGF Project components generally follows the accounting for capital expenditure and software projects approved by the Commission in the past. In general, the cost of equipment and hardware and their related capital expenditures will be capitalized in accordance with Generally Accepted Accounting Principles ("GAAP") and the Companies' current accounting for such costs.

Until their first respective rate case(s) following completion of the SGF Project, the Companies are proposing to recover the SGF Project and related ongoing costs (net of Operational Benefits) through the Renewable Energy Infrastructure Program ("REIP") surcharge ("Surcharge") as described in the *Joint Proposed Modified Renewable Energy Infrastructure Program Framework* ("Modified REIP Framework") filed by the Companies and Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs ("Consumer Advocate") on June 15, 2015 in Docket No. 2013-0141.[3] There are certain nuances to the SGF Project that necessitated some tailoring of the application of the Modified REIP Framework to address fairness in the context of cost recovery issues that can arise in connection with complex undertakings such as the SGF Project. In order to address the unique and transformational nature of the SGF Project, as well as its interrelated components, magnitude and duration, the Companies are proposing certain measures to provide flexibility and further tailor the REIP Surcharge to address the costs, benefits and timing of the various project components – namely, the contemporaneous recovery of certain pre-in-service/go-live expenses via the REIP Surcharge.

For purposes of calculating the bill impact of the SGF Project (i.e., the amounts to be included in the REIP Surcharge and subsequent regulatory rate reviews to determine energy rates), the SGF Project costs are offset in part by the Operational Benefits (but not the Direct

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[3] See generally Order No. 37235 ("Order 37235"), filed March 31, 2015 in Docket No. 2013-0141.

Customer Benefits, which are included in the economic analysis discussed above) of the investment. Over the twenty-year life of the investment, the bill impact for a typical residential customer will range between $0.56 and $4.43. The average bill impact at Hawaiian Electric, Maui Electric and Hawai‘i Electric Light is estimated to be $2.01, $2.05 and $2.75, respectively.

The Companies are cognizant of the Commission's direction that the Companies' filings should not assume approval of the merger that is pending in Docket No. 2015-0022. However, in light of the Commission's request in other pending dockets that a "merged scenario" be provided in order to allow for discussion on how the proposed change in ownership would impact the SGF Project, NextEra Energy, Inc. ("NextEra Energy") has provided a SGF Project business case under a scenario that assumes the merger of NextEra Energy and the Hawaiian Electric Companies is approved ("Merged Business Case").[4]

The major differences between the Merged Business Case and the Companies' Business Case are that: (1) AMI implementation would be accelerated from five to three years; (2) supply chain costs for some equipment and outside service costs would be reduced by 5%; (3) some solutions being used by NextEra Energy's subsidiary Florida Power & Light Company ("FPL") could be leveraged (e.g., FPL's MDMS and ESB); and (4) key FPL personnel would provide additional expertise, thus mitigating project execution risks. The Companies have already been working with NextEra Energy in planning the SGF Project and accordingly, many of FPL's lessons learned have already been incorporated into the SGF Project during the initial design and development of the application. In sum, the Merged Business Case indicates that the merged

[4] See Exhibit I.

companies will be able to bring SGF Project benefits to Hawaiʻi's residents faster, at a lower cost and with lower overall risk.

II. REQUESTED APPROVALS

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

(1) the total estimated cost to implement the SGF Project ("SGF Project Costs") of approximately $340 million, including $206 million of capital costs ("Capital Costs"), $75 million of deferred costs ("Software Development Costs" or "Deferred Costs") and $59 million of incremental expense items ("Expense") as discussed in Section VIII.A below and further detailed in Exhibit B;

(2) The accounting and ratemaking treatment proposed to be applied to the SGF Project, as discussed in Section IX below and further detailed in Exhibit F, including:

(a) a commitment of funds in excess of $2,500,000, excluding customer contributions for the Capital Costs under Paragraph 2.3(g)(2) ("Rule 2.3(g)(2)") of the Commission's General Order No. 7, as modified by Decision and Order No. 21002 filed May 27, 2004 in Docket No. 03-0257;

(b) deferral of the Software Development Costs pursuant to the Companies' policy for *Accounting for the Costs of Computer Software Developed or Obtained for Internal Use* ("Software Accounting Policy") and Decision and Order No. 18365 ("D&O 18365") filed February 8, 2001 in Docket No. 99-0207 ("Hawaiʻi Electric Light 2000 test year rate case) and accrue an allowance for funds used during construction ("AFUDC") during the deferral period, and/or, if the Commission deems such approval to be necessary, to commit expenditures in excess of $2,500,000 for the Software Development Costs pursuant to Rule 2.3(g)(2);[5]

(c) depreciation of the Capital Costs in accordance with the Companies' *General Accounting Guidelines, Accounting for Capital Project Costs* ("Capital Project Accounting Policy"), including depreciation of the new AMI meters ("smart meters") over a 20-year period;

(d) amortization of the Software Development Costs in accordance with the Software Accounting Policy over a 12-year period;

(e) amortization of the remaining book value (currently estimated at approximately $51 million) of the Companies' existing non-AMI meters over a 10-year period; and

(f) recovery as discussed in Section X below and further detailed in Exhibit G, of the revenue requirements associated with the Capital Costs, Software Development Costs and certain other relevant expenses ("Relevant Expenses") including: (i) Pre-In-Service/Go-Live Expenses; (ii) post-in-service/go-live ongoing expenses

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[5] If necessary, in an abundance of caution, the Companies are also seeking approval under G.O. 7 of any other costs of the SGF Project for which the Commission may determine that G.O. 7 approval is required. In the Companies' CIS docket (Docket No. 04-0268), the Consumer Advocate noted that the costs "proposed to be deferred" exceeded the $2.5 million G.O. 7 threshold. The Companies' position was that the software development costs to be deferred did not fall within the scope of Rule 2.3(g)(2) but instead should be treated as a deferred cost to be handled in an application as directed by D&O 18365. See Decision and Order No. 21798 ("D&O 21798"), filed May 3, 2005 in Docket No. 04-0268 at 35. The Commission issued similar rulings on this issue in the Companies' OMS proceeding (see Decision and Order No. 21899, filed June 30, 2005 in Docket No. 04-0131 at 15), HR Suite proceeding (see Decision and Order No. 24313, filed May 3, 2007 in Docket No. 2006-0003 at 22) and BSR proceeding (see Decision and Order, filed November 2, 2011 in Docket No. 2010-0339 at 25-26). In D&O 21798, filed May 3, 2005 in the CIS docket, the Commission held that "it need not decide in this instance whether the Utilities must file an application for approval of a capital expenditure project under G.O. No. 7" on the grounds that "if this Application is approved by the commission, it would achieve the same end result as if the Application were filed under G.O. No. 7." D&O 21798 at 36.

("Post-In-Service/Go-Live Ongoing Expenses"); and (iii) customer engagement expenses ("Customer Engagement Expenses") through: (A) the REIP Surcharge as proposed in the Modified REIP Framework; or in the alternative, (B) the existing REIP Surcharge approved in the *Decision and Order* filed on December 30, 2009 in Docket No. 2007-0416 ("Existing REIP Surcharge"), until base rates that reflect the unrecovered SGF Project Costs take effect in each of the Companies' first respective rate cases after the SGF Project has been completed, with:

i. relevant costs and Operational Benefits of the SGF Project included in the REIP Surcharge on a quarterly basis and trued-up annually;

ii. a carrying charge applied at the Companies' respective short-term debt rates to the SGF Project Costs and Relevant Expenses (including any deferred depreciation and amortization expenses that the Companies may incur prior to the onset of REIP Surcharge recovery) between the in-service/go-live date of each respective component, subproject, deployment and/or release, as the case may be (each, a "Release") and the commencement of REIP Surcharge recovery for each Release;

iii. a return at the Companies' respective AFUDC rates on the unrecovered Capital Costs and deferred Software Development Costs from the commencement of REIP Surcharge recovery until base rates that reflect the unrecovered amounts take effect in the Companies' respective rate cases; and

iv. contemporaneous inclusion of the Relevant Expenses in the REIP Surcharge as incurred, or in the alternative, deferral for subsequent recovery of the Pre-In-Service/Go-Live Expenses and Customer Engagement Expenses until the in-service/go-live of each respective Release;

(g) in the alternative, if the Commission does not allow the Companies to seek recovery through the REIP Surcharge, deferral of the SGF Project Costs and Relevant Expenses until base rates that reflect the SGF Project Costs and Relevant Expenses take effect in each of the Companies' respective rate cases over the duration of the SGF Project and/or their first respective rate cases after the SGF Project has been completed, with accrual of appropriate carrying charges; and

(3) waivers as discussed in Section XI below of:

(a) G.O. 7 paragraphs 4.5(a) ("Rule 4.5(a)"), 4.5(d)(1) ("Rule 4.5(d)(1)") and 4.5(d)(2) ("Rule 4.5(d)(2)"), and Tariff Rule No. 11.B ("Rule 11.B") of each company so that the Companies can temporarily suspend back-billing for slow meters during the SGF Project;

(b) G.O. 7 paragraph 6.1(e), as amended by Order No. 8373 filed June 17, 1988 in Docket No. 5088 ("Rule 6.1(e)") and Tariff Rule No. 11.A.1 ("Rule 11.A.1") of each company, so that the Companies can temporarily suspend the annual in-service performance testing for all meters during the SGF Project; and

(c) Tariff Rule No. 14.A.2.a ("Rule 14.A.2.a"), insofar as it would require a residential customer to pay for repairs to a meter socket that: (1) is damaged in the course of a smart meter installation; and/or (2) does not appear to be damaged prior to the smart meter installation, but is found to be damaged during the installation; and

(4) the Non-Standard Meter ("NSM") Service tariff discussed in Section XII below and provided as Exhibit H.

III. APPLICANTS

Hawaiian Electric, whose principal place of business and executive offices are located at 900 Richards Street, Honolulu, Hawaiʻi, is a corporation duly organized under the laws of the Kingdom of Hawaiʻi on or about October 13, 1891, and is now existing 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 executive office is located at 1200 Kilauea Avenue, Hilo, Hawaiʻi, is a corporation duly organized under laws of the Republic of Hawaiʻi on or about December 5, 1894, and is now existing 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, State of Hawaiʻi.

IV. CORRESPONDENCE

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

Daniel G. Brown
Manager, Regulatory Non-Rate Proceedings
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P. O. Box 2750
Honolulu, Hawaiʻi 96840-0001

V. EXHIBITS

The following exhibits are provided in support of this Application:[6]

Exhibit A: Smart Grid Strategy and Roadmap

Exhibit B: Hawaiian Electric Companies' Business Case

Exhibit C: Customer Engagement Activities

Exhibit D: Smart Grid Customer Safeguards

Exhibit E: Vendor Selection

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[6] Exhibit E contains confidential vendor pricing information, other proprietary information which could be used to deduce the confidential vendor pricing information, and/or other non-public contractual provisions which, if publicly exposed, could place the Companies at a disadvantage in future contract negotiations and/or place the vendors at a business disadvantage with respect to industry competitors. In addition, Exhibit B, Attachments 9 and 10 contains other forms of confidential vendor information, including proprietary business methods, analytical tools and/or other non-public information which, if publicly disclosed, could harm the Companies' relationships with existing and prospective vendors. Moreover, Exhibit B, Attachments 9 and 10 and Exhibit E, Attachments 5 and 6 contain confidential information concerning the Companies' critical infrastructure and information technology architecture which, if publicly disclosed could present a risk to the Companies' electric systems and operations. Further, Exhibit B, Attachment 10 contains confidential and/or proprietary information that could competitively disadvantage the Companies if publicly disclosed.

To the extent reasonably practicable, the confidential information has been redacted from Exhibit E. However, it would be unduly burdensome to make select redactions from certain attachments to Exhibit B and E and therefore, the Companies have redacted entire pages from those attachments. Due to the volume and/or proprietary nature of the confidential information contained in Exhibit B and E, it would be impracticable to redact all of the confidential information from those documents. The Companies will file unredacted versions of any pages from which confidential information has been redacted upon issuance of an appropriate protective order in this docket.

Exhibit F: Accounting and Ratemaking Treatment

Exhibit G: REIP Surcharge Recovery

Exhibit H: Non-Standard Meter Service Tariff

Exhibit I: Merged Business Case

VI. BACKGROUND

As discussed in Exhibit A, Smart Grid is a key component of the Hawaiian Electric Companies' business strategy and ongoing transformation into a next generation energy company that is committed to improving the way energy is delivered using new technologies that benefit customers. Smart Grid is defined as the integration and application of real-time monitoring, advanced sensing, communications, analytics and control that enables the dynamic flow of both energy and information to accommodate existing and new forms of energy supply, delivery and use in a secure, reliable and efficient electric power system from generation source to end-user.[7]

In April 2014, the Commission set forth broad principles and perspectives on its view of the electric utility business in its *Inclinations on the Future of Hawaii's Electric Utilities* ("Commission's Inclinations").[8] The Commission's Inclinations specifically note that: "Hawaii should be poised to lead the world in the development of advanced grids. . . ."[9] The concerns, observations and directives set forth in the Commission's Inclinations have subsequently been

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[7] As defined by the North American Electric Reliability Corporation ("NERC") Smart Grid Task Force ("SGTF") report: *Reliability Considerations from the Integration of Smart Grid*, dated December 2010, Executive Summary, available at http://www.nerc.com/files/SGTF Report Final posted vl.l.pdf.

[8] See Exhibit A to Decision and Order No. 32052 ("D&O 35052"), filed April 28, 2014 in Docket No. 2012-0036 (Integrated Resource Planning proceeding).

[9] Id. at 10-11.

incorporated into the Companies' 2015-2020 Strategic Transformation Plan ("Strategic Transformation Plan"),[10] which sets forth the Companies' mission to provide innovative energy leadership for Hawai'i.

Realizing the Companies' vision to empower customers and communities with affordable, reliable, clean energy from sources that help reduce environmental impacts is not possible with the Companies' current electric system. However, the Companies believe that they can achieve this vision and meet the State's 100% RPS goal in a manner that is cost-effective for all of the Companies' customers by transforming the way they do business, including the creation of a modernized and intelligent power grid that utilizes Smart Grid technologies and improves the value proposition to customers by increasing visibility and control, and providing a suite of products and services to meet customer' various energy needs and preferences.[11]

In general, a Smart Grid refers to an electric utility delivery system that uses computer based remote control and automation. As described by the U.S. Department of Energy ("DOE"):

> Much in the way that a "smart" phone these days means a phone with a computer in it, smart grid means "computerizing" the electric utility grid. It includes adding two-way digital communication technology to devices associated with the grid. Each device on the network can be given sensors to gather data (power meters, voltage sensors, fault detectors, etc.), plus two-way digital communication between the device in the field and the utility's network operations center. A key feature of the smart grid is automation technology that lets the utility adjust and control each individual device or millions of devices from a central location.[12]

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[10] The Strategic Transformation Plan was provided as Attachment 1 to the response to CA-IR-376 in Docket 2015-0022 (NextEra Energy, Inc. ("NextEra Energy") merger proceeding).

[11] Act 97, 2015 Haw. Sess. L., which was effective as of July 1, 2015, modified the RPS law by changing the December 31, 2020 goal from 25% to 30%, and adding two additional goals: (1) 70% of its net electricity sales from renewable energy by December 31, 2040; and (2) 100% of its net electricity sales from renewable energy by December 31, 2045.

[12] Available at http://energy.gov/oe/services/technology-development/smart-grid.

The Companies' Smart Grid vision is to provide an increasingly intelligent and automated electric system that utilizes technology advancements to leverage capabilities in telecommunications, computing, sensing and controls for transmission and distribution to all service locations via a multi-direction flow of energy and information to better meet customers' expectations, the State's energy policy objectives, communities' energy demands, and the Companies' overarching responsibility to provide safe, reliable and secure electric service. Smart Grid will modernize the Companies' power grids, enabling a more seamless integration of renewable energy produced entirely from constantly-replenished natural resources (e.g., using advanced inverters), increasing reliability and efficiency (e.g., using smart storage), helping the environment, and providing customers with greater visibility of their energy usage (e.g., using smart meters), as well as more options for energy choices (e.g., by offering new rate options).

Building a Smart Grid in Hawaiʻi will not be accomplished in a single project effort, but will evolve over time, by growing and layering capabilities and functionality that increasingly deliver more and more value to customers. The need for such an iterative and phased approach increases the value of the initial Smart Grid installation and subsequent components, as each additional component that is layered over the foundational platform leverages existing capabilities, thereby increasing the value of the infrastructure (including renewable energy infrastructure such as the smaller and localized energy generating resources that are already in place at customers' premises) already in place. Thus as illustrated in Figure 1 below, the Smart Grid Roadmap divides Smart Grid into two major stages: (1) a "Base Stage," in which the basic capabilities and foundational infrastructure are assessed, implemented, operated and monitored; and (2) an "Enhancement Stage," in which additional capabilities that have yet to be fully commercialized are layered on top of the base in order to complete the implementation of a modern power grid that realizes the Companies' Smart Grid vision.

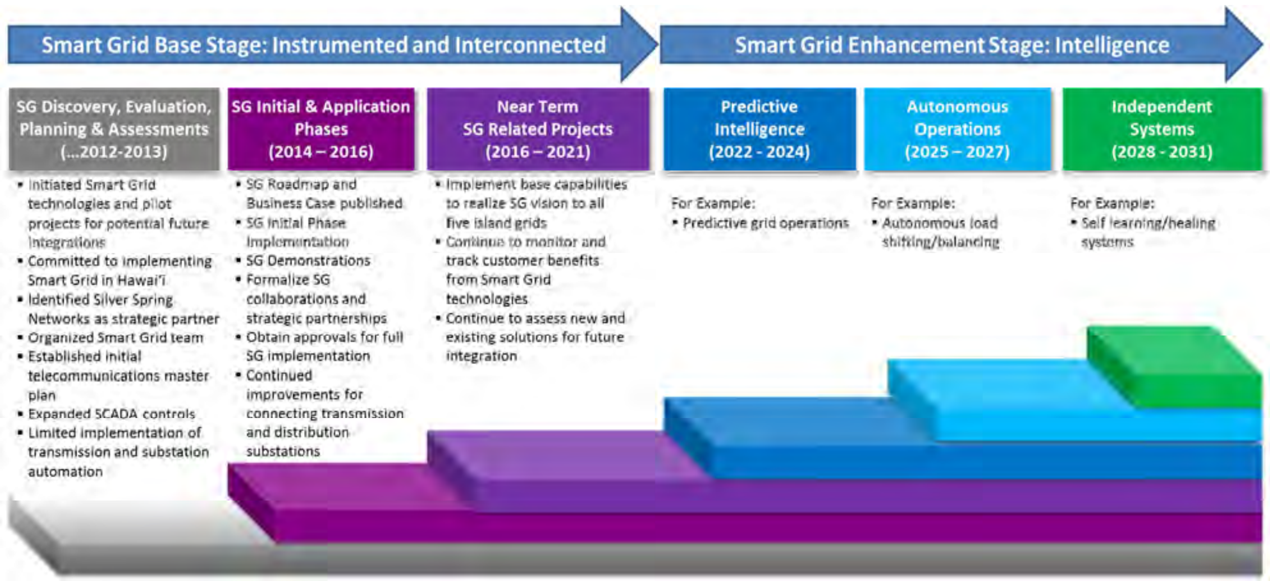

Figure 1

The Companies have already completed the smart grid discovery, evaluation, planning and assessments phase and are in the smart grid initial and application and near term SG related projects phases of the Smart Grid Base Stage. For example, the Initial Phase completed in 2015 was deployed on select circuits on O'ahu for approximately 5,200 residential, small business and commercial & industrial ("C&I") customers. During the Initial Phase, smart meters, access points, and communication relays were installed and layered upon SSNI's AMI network.

The Companies' Smart Grid efforts have already been guided by the results of the Base Stage activities, including the Initial Phase, various pilot projects, peer energy company lessons learned and the strategic partnership with SSNI, and are now well on their way toward the near-term smart grid related project phase in which the foundation of the smart grid will be implemented. The near-term ("Near-Term") view of six years (2016 through 2021) provides a working construct of interdependent Smart Grid-related projects that "connect the dots" between the Companies' various plans, strategies and dockets before the Commission, which include interconnected planning assumptions that not only provide the basis for scope and timing, but also for its inter-dependencies. For example, it is not possible to offer real-time pricing without a MDMS that is linked to an installed base of smart meters.

Once this Near-Term phase is finished, the overall Base Stage will be completed and the Enhancement Stage will begin, with an increased focus on enhancing the Smart Grid capabilities and leveraging new technology advancements in predictive, autonomous and independent systems. However, none of this will be possible without first installing AMI and carrying out the related initiatives to create the backbone of the Smart Grid.

VII. SMART GRID FOUNDATION PROJECT

The SGF Project provides for a bundle of Smart Grid capabilities that are considered foundational to the five key strategic areas identified in the Smart Grid Roadmap:

(1) *Customer empowerment* capabilities that that allow customers to monitor their energy use patterns and make informed adjustments that can reduce their consumption and lower energy expenses, as well as enabling a more convenient means to participate in money saving rate options such as TOU rates;

(2) *DER integration* capabilities that will allow more customers to have DER sooner, as a result of smart meters providing increased visibility into the power grid;

(3) *Grid efficiency, reliability and resiliency* capabilities that will use smart meters as sensors to automatically detect power outages and to enable faster

restoration of power, as well as enable the Companies to burn less fuel to meet customer demand for energy;

(4) *Safety and workforce efficiency* improvements enabled by remote capabilities that enable better detection of energy theft and eliminate the need for the Companies' personnel to enter customer premises, which means fewer accidents, faster service connections, more accurate billing and fewer interruptions for customers; and

(5) *Innovation, information and connectivity* that will make it easier for new smart technologies (as developed) and customer-sited generation to integrate into the Smart Grid and leverage the smart infrastructure for many uses, while proactively keeping customer data safe, private and secure.

At a high level, the SGF Project will establish:

- the multipoint communications network necessary to increase the amount of information and control of the grid to the levels required by Smart Grid products and services;
- serve as the platform to future Smart Grid-related functionality, such as DR, TOU rates and RTP, that allow customers to save money by rewarding them for reducing their energy usage during periods of peak demand; and
- provide the initial functionality to improve grid reliability and enhance customer options.

As detailed in Exhibit B, the SGF Project consists of ten interrelated components: (a) eight subprojects: (1) AMI; (2) CFS; (3) CVR; (4) DLC; (5) EDW; (6) ESB; (7) MDMS; and (8) OMS; (b) a ninth component for customer engagement activities to help customers to maximize the benefits of the new Smart Grid technologies; and (c) a tenth component for project management services that also support the eight subprojects and customer engagement activities listed above.

In short, the SGF Project is necessary for Hawai‘i to achieve its renewable energy future and for the Companies’ customers to receive next generation value through state-of-the-art energy delivery systems and cost-effective, clean, reliable, and innovative energy services. Further, the SGF Project is consistent with the Commission’s Inclinations and its guidance as to the development and implementation of smart grid and advanced metering infrastructure programs - including its focus on delivering immediate value and benefits to customers, enabling customer-sited distributed energy resources, working with third party service providers, and development of data privacy policies.[13]

A. SUBPROJECTS

The scopes of the eight subprojects have been tailored based on a “best-fit/least-cost” approach that utilizes commercially available and proven cost-effective technologies to deliver the key foundational Smart Grid capabilities and immediate value and benefits to customers. Although additional solutions exist that utilize the Smart Grid infrastructure, such as Distribution Automation (DA) which includes the Advanced Distribution Management System (“ADMS”), the Companies have decided to continue to monitor and test the viability of these and other

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[13] See Commission’s Inclinations at 14-15.

Smart Grid applications and will consider the appropriateness of adding them to the Companies Smart Grid in the future.[14]

1. Advanced Metering Infrastructure

Installation of AMI will provide two-way communications and control between the Companies and the installed smart meters that support the innovation, information and connectivity capabilities of the Smart Grid, and serve as the fundamental building block of the overall Smart Grid implementation. Through AMI, the Companies and their customers will be able to determine energy consumption and voltage at individual customer premises at periodic intervals and on demand, as opposed to the existing non-AMI meters which do not provide any voltage information and require the Companies to send a meter reader to the location to obtain energy consumption. AMI also introduces enhanced functionalities that will allow for on-demand features that are not available with the manual processes the Companies currently have in place, such as remote disconnects and reconnects, remote meter reading and voltage control.

AMI will be deployed across all five of the Companies' service territories islands (Oahu, Hawai‘i Island, Maui, Moloka‘i and Lana‘i). The Companies are targeting the installation of smart meters for more than 97% of their customers (equating to approximately 467,000 total smart meters installed).

At a high level and as further detailed in Section VIII below, AMI will result in Operational Benefits to customers related to: (1) the reduction in labor and associated costs specific to manual meter reading; (2) the avoided costs associated with the purchase, installation

[14] See the Smart Grid Roadmap for information on the near future filing of the DA project application.

and testing of non-AMI meters; (3) the reduced overhead surrounding customer service representatives who handle billing and service scheduling calls; (4) the reduction in costs specific to system operations; and (5) the increased efficiency of the billing and receivable processes, and reduced energy theft.

2. Customer Facing Solution

The CFS subproject will provide online and mobile pathways for two-way communication between customers and the Companies, while improving the customer experience and empowering customers to better manage their energy usage. The expanded capabilities include, but are not limited to providing customers: (1) access to accurate energy usage data and trending analysis information so they can better plan for future energy needs; (2) information and alerts about their energy consumption to allow them to better manage their monthly energy costs; (3) options to examine and compare available rates; (4) easier enrollment in available programs, such as DR programs that reward customers for smart energy usage; and (5) near-real-time information about service outages in their areas.

CFS will be installed in four phases. At the end of the first phase, customers will have access to the new energy portal allowing customer account registration, account authentication, development of the online account landing page, customer preference designations, service/account alerts, multiple-account modification/access and overall customer account display. The second phase will provide integrated features and functions that provide billing based on detailed interval data that supports the introduction of flexible programs such as TOU. The third phase will specifically provide features and functions that automate processes such as remote connect and disconnect and support more near real-time service requests including programs enrollments. The fourth phase will integrate expanded near-real-time outage communications features and functions that enable customers to send/receive service interruption information directly to/from the Companies.

At a high level, the benefits associated with the CFS will flow directly to customers as a result of customers reducing their own energy use. The CFS will also result in intangible benefits related to increased customer convenience and improved customer satisfaction.

3. Conservation Voltage Reduction

CVR technologies support the grid efficiency, reliability and resiliency capabilities by using voltage measurements from the smart meters to enable the Companies to improve efficiencies and burn less fuel to generate energy to meet demand. The CVR subproject will enable the Companies to collect consumption and voltage information at customers' premises from the smart meters over the AMI network. The Companies' system operators will use this information to more accurately and dynamically control voltage fluctuations at the distribution level.

In general, voltages are maintained on the higher side of the allowable voltage limits, in order ensure power quality. The collected voltage information will enable the Companies to fine tune voltages at distribution transformers to a more optimal setting (this generally means lowering voltage), which should result in a decrease of overall energy consumption, without requiring any changes to the customer's energy usage behavior. Ultimately, this decrease in consumption will enable the Companies to spend less on the fuel necessary to generate the energy to meet demand. This cost savings will be passed on to the customers through the Companies' respective Energy Cost Adjustment Clauses ("ECAC").

CVR is primarily suitable on circuits that are shorter and more heavily-loaded. As a result, it is only planned for installation on 45% of O'ahu distribution circuits, 66% of Maui distribution circuits and 70% of Hawai‘i Island distribution circuits. The Companies do not plan to deploy CVR on Lana‘i or Moloka‘i.

4. Direct Load Control

The DLC subproject will upgrade existing DLC switches on O‘ahu to improve monitoring and performance of participating customers' water heater operations and stabilize the power grid during peak demand, in support of the DER integration capabilities. Specifically, the DLC subproject will replace the existing end-of-life, one-way DLC switches with two-way DLC switches communicating via the AMI network provided by SSNI. The new switches will provide greater two-way information flow which will facilitate better control and performance of the EnergyScout program,[15] while simultaneously leveraging the SSNI network for multi-purpose uses beyond AMI. The scope of the DLC subproject is limited to Hawaiian Electric customers already enrolled in the existing EnergyScout program, in accordance with the Commission's directive on page 21 of its *Decision and Order* filed on December 29, 2009 in Docket No. 2009-0097.

Enabling the Companies to periodically turn off a customer's electric water heater supports system operations to balance the system frequency during the loss of generation, or to balance system load during an increase in system demand (creating the risk of a generation capacity shortfall). Turning off a water heater during these emergency periods allows the system

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[15] In 2005, Hawaiian Electric provided customers the option to enroll in two different EnergyScout programs (i.e., water heater and air conditioning) aimed at providing the Companies options for load curtailment and control, when necessary, to better manage the grid. In 2008, the program was considered mature with more than 30,000 participants.

operator to operate the power grid in a safe manner, and in some cases, can help the system avoid rolling blackouts.

5. Enterprise Data Warehouse

The EDW subproject will develop the central repository of the large amounts of data gathered over the AMI network and other company data used to improve electric service to customers. This includes system operating data that will be acquired by the deployed technologies in the SGF Project, as well as other interconnected programs, such as DR and any future projects that the Companies pursue to enhance the grid's functionalities. The current and historical data will then be used to enhance analysis and reports for use throughout the Companies.

As a key component of the Smart Grid infrastructure, the primary value of the new EDW lies in its ability to enable analysis of large amounts of Smart Grid disparate data from different systems into a single cohesive data model. This includes customer, economic and operational data for purposes of forecasting and modelling the inherent complexities of a next generation energy company.

6. Enterprise Service Bus

The ESB subproject will enhance the Companies' existing ESB to enable seamless flow of data through the Companies' various computer systems, also in support of the innovation, information and connectivity capabilities of the Smart Grid. Specifically, this subproject is necessary to expand the utility of the Companies' existing software. It will facilitate increased automation, as well as efficiency and more seamless and secure flow of Smart Grid data collected from the smart meters or circuits through all of the Companies' systems (e.g., the

DRMS, OMS and MDMS). Similar to the EDW, the Companies will enhance the existing ESB to accommodate the immense volume of data that will now be gathered over the AMI network.

7. Meter Data Management System

The MDMS that will capture and manage the customer interval energy usage data obtained from the smart meters to enable automated billing and operational efficiencies such as reduced truck rolls from eliminated manual meter reads. The MDMS subproject is a key component in the SGF Project that will enable the following functions: (1) collection of meter data; (2) validation, estimation and editing; (3) versioned meter data storage; (4) billing/usage calculation and aggregation; and (5) application interfaces and data integration. The primary purpose of this system is to manage the large volume of interval data collected from smart meters for billing purposes.

The MDMS subproject will be deployed in two phases. The first phase includes integration work from the ESB, populating the new EDW with the MDMS data and modification of the CIS to obtain readings and billing determinant data from the MDMS. The second phase will continue to use the MDMS system to obtain interval data reads from the smart meters, but will also validate and provide billing determinants to be used to calculate customer bills. The second phase will also implement automation to remotely connect or disconnect services as related to move in/move out and credit connect/disconnect processes, as well as to integrate the MDMS, ESB and EDW solutions in support of the newly enabled functions.

The MDMS is sometimes thought of as the "brain" of an AMI network. Without the MDMS, the Companies would not be able to support flexible programs that require detailed usage information, or have the ability to augment such programs via remote automated configuration.

8. Outage Management System

The OMS subproject will enhance Hawaiian Electric's OMS on O'ahu and expand it to Maui Electric and Hawai'i Electric Light in order to improve outage communications, and increase the speed and efficiency of power restoration. An OMS is a computer system used by operators of electric distribution systems to assist in the restoration of power in the event of an outage.

The OMS subproject will leverage the Hawaiian Electric's existing OMS and add additional capabilities that will capture information from the new smart meters over the AMI network to monitor, identify and inform system operators of outages on the respective distribution systems. The Companies currently have no direct visibility into the status of electricity at a customer's premises, and therefore, rely on customers to call the Companies in the event of an outage. The AMI network will not only enable the Companies to read smart meters remotely, but also provide the ability to detect outages automatically without customers' help. In the event of an outage at a customer's premises, the smart meter will be configured to send a "last gasp" message to inform the Companies' system operators of the outage. This will reduce the duration of service interruptions and increase the efficiency of the Companies' outage responses and power restoration.

At a high level the Operational Benefits and Direct Customer Benefits of the OMS include: (1) more accurate determination of the location of a blown fuse or knowledge of a circuit breaker tripping; (2) prioritizing restoration efforts and managing resources based on various criteria such as locations of emergency facilities, and size and duration of outages; (3) providing information on extent of outages and number of customers affected to management, media and regulators; (4) calculation of estimation of restoration times; and (5) more effective management of crews assisting in restoration. This will result in quicker restoration times in the event of an outage as well as better information for outage notification to customers.

B. CUSTOMER ENGAGEMENT

The Customer Engagement component of the SGF Project consists of activities to help customers maximize the benefits of the new Smart Grid technologies and support the eight subprojects discussed above. As detailed in Exhibit C, the customer engagement activities carried out in connection with the Initial Phase indicate that in order to be successful, the SGF Project will require a proactive, targeted, collaborative, responsive and flexible communications effort to educate and engage with customers throughout the implementation. Consistent with the results of prior Smart Grid implementations at other utilities, the lessons learned from the Initial Phase revealed that engaging customers early and often provides customers with more opportunities to learn about the benefits of Smart Grid technologies and allows them to make more informed decisions.

The same general customer engagement principles will be applied to the SGF Project, with a focus on helping customers reduce their energy usage, improve safety and service reliability, and support Hawai‘i’s clean energy transformation. As the SGF Project progresses, the Companies intend to continue engaging customers through community outreach, customer education, government relations, third-party engagement, media relations, customer research, employee engagement and customer service support.

The customer engagement activities carried out in the Initial Phase revealed that it is important to customers that appropriate safeguards are in place to address potential issues with emerging technologies. As discussed in Exhibit D, the Companies top priority is the health, safety, privacy and security of their customers, employees and the general public. Some of the more common concerns expressed by customers in the Initial Phase were related to: (1) whether radio frequency ("RF") signals from smart meters are safe; (2) whether smart meters will increase the risk of meter-related fires at customer premises; and (3) whether transmitting customer usage information over the Smart Grid communications network will affect privacy and security. The Companies have taken substantial steps beyond state and federal safety guidelines to address these concerns in the SGF Project.

For example, as discussed in Attachment 5 to Exhibit D, in order to protect against new and existing vulnerabilities related to cyber-threats, the SGF Project will enhance and add new cybersecurity solutions that are designed to protect, monitor and manage such threats so that they are prevented and/or responded to with immediacy. This includes fortifying existing mitigations such as multi-level access controls, anti-virus software and a variety of intrusion sensors, while providing for additional security zones, more rigorous data management, and new security information and event management capabilities.

C. PROJECT MANAGEMENT OFFICE

The SGF Project is complex and unique in terms of its transformational nature, inter-related components, magnitude and duration. Given the importance of the SGF Project to customers and Hawaii's energy future, the Companies have taken great care to ensure that any potential risks to the project are mitigated to the greatest extent possible. The PMO component of the SGF Project is project management services to support the eight subprojects and customer engagement activities, in order to ensure smooth, cost-effective and coordinated project execution. These project management services consist of: (1) project governance; (2) cross-project coordination; (3) centralized procurement, contracts and vendor management; (4) project administration, support, controls and reporting; and (5) organizational change management and process improvement.

D. PROJECT SCHEDULE

The SGF Project is scheduled to be implemented over five years beginning immediately upon the issuance of a decision and order enabling the project to commence, which is currently assumed to be in early 2017. Each subproject has its own schedule with its own commencement and in-service/go-live date(s) as illustrated in the Figure 2, below.

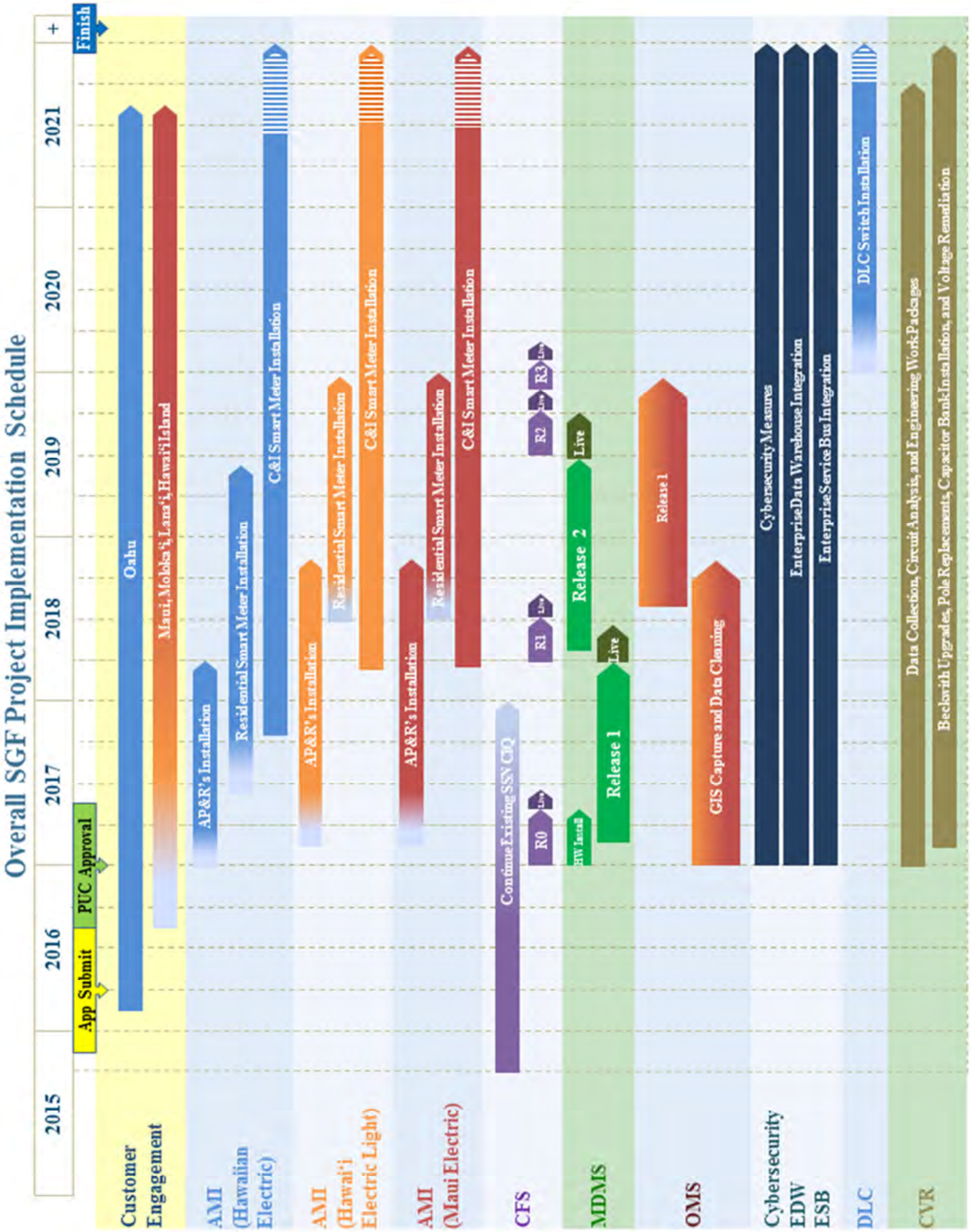
Overall SGF Project Implementation Schedule
2015
2016
2017
2018
2019
2020
2021
+
App Submit
PUC Approval
Finish
Customer Engagement
Oahu
Maui, Moloka'i, Lana'i, Hawai'i Island
AMI (Hawaiian Electric)
AP&R's Installation
Residential Smart Meter Installation
C&I Smart Meter Installation
AMI (Hawai'i Electric Light)
AP&R's Installation
Residential Smart Meter Installation
C&I Smart Meter Installation
AMI (Maui Electric)
AP&R's Installation
Residential Smart Meter Installation
C&I Smart Meter Installation
CFS
Continue Existing SSN CIQ
R0
Live
R1
Live
R2
Live
R3
Live
MDMS
HW Install
Release 1
Live
Release 2
Live
OMS
GIS Capture and Data Cleaning
Release 1
Cybersecurity
Cybersecurity Measures
EDW
Enterprise Data Warehouse Integration
ESB
Enterprise Service Bus Integration
DLC
DLC Switch Installation
CVR
Data Collection, Circuit Analysis, and Engineering Work Packages
Beckwith Upgrades, Pole Replacements, Capacitor Bank Installation, and Voltage Remediation

Figure 2

At a high level, work to mobilize the vendors and procure the hardware and equipment will begin immediately upon commencement of the SGF Project along with work on the MDMS, CFS, EDW and ESB subprojects. The Customer Engagement activities will also begin immediately upon commencement of the SGF Project, roughly a quarter ahead of the AMI rollout on O‘ahu. Commencement of the AMI rollout at Maui Electric and Hawai‘i Electric Light will follow the AMI rollout on O‘ahu by roughly one year. The majority of the work on the OMS subproject is scheduled to begin in 2018 upon completion of the requisite data cleansing that will be carried out in 2017. The majority of the work on the DLC subproject will be carried out in the 2020-2021 timeframe in order to align with the timing of the required end-of-life replacement of the existing switches. Additional details regarding each subproject schedule are provided in the respective subproject cost descriptions in Exhibit B.

VIII. SGF PROJECT BUSINESS CASE

As discussed above, throughout its progressive implementation, Smart Grid will play an increasingly pivotal role in Hawai‘i’s energy future. When viewed in isolation, without considering some benefits which are difficult to quantify and the subsequent projects and benefits that will be enabled with the foundational technology for the SGF Project, the SGF Project alone does not have a positive BCR. However, as explained in the Companies’ Smart Grid Roadmap, the value proposition for a Smart Grid is unique in that many of its related benefits are community-based, complex and/or difficult to directly quantify. Building a Smart Grid in Hawai‘i will not be accomplished in a single project effort, but will evolve over time, growing and layering capabilities and functionality that increasingly deliver incremental value to customers. Each additional component that is layered over the SGF Project platform will leverage existing capabilities, thereby increasing the value of the infrastructure already in place.

When taken in their entirety, the overall bundle of benefits and capabilities enabled by Smart Grid supports an overall positive business case that will increase capabilities and lower costs in the long run.

A. PROJECT COSTS

The total nominal cost of the SGF Project over its five-year implementation is estimated at $340 million.

Hawaiian Electric Companies Consolidated Five-Year SGF Project Implementation Costs by Accounting Treatment (Nominal $000s)

Component	Capital	Deferred	Expense	Total
AMI	162,814	2,229	20,819	185,862
CFS	15	6,102	2,796	8,912
CVR	21,758	1,201	3,902	26,861
DLC	17,913	615	942	19,470
EDW	6	4,548	5,617	10,172
ESB	996	5,327	4,208	10,531
MDMS	1,996	43,842	5,887	51,725
OMS	42	11,212	6,836	18,091
CE	9	-	8,403	8,412
Total	**205,549**	**75,077**	**59,409**	**340,035**

Note: Includes all applicable taxes, AFUDC and allocated PMO costs.

Table 3 below provides a summary of the costs of the eight SGF Project subprojects and customer engagement component by accounting treatment for the consolidated Hawaiian Electric Companies. In order to show the total cost of each of these items, the costs for the PMO component are included in each of the SGF Project components within the table.

Hawaiian Electric Companies Consolidated Five-Year SGF Project Implementation Costs by Accounting Treatment (Nominal $000s)				
Component	Capital	Deferred	Expense	Total
AMI	162,814	2,229	20,819	185,862
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CE	9	-	8,403	8,412
Total	**205,549**	**75,077**	**59,409**	**340,035**
Note: Includes all applicable taxes, AFUDC and allocated PMO costs.				

Table 3

The Capital Costs, Deferred Costs and Expenses shown in **Hawaiian Electric Companies Consolidated Five-Year SGF Project Implementation Costs by Accounting Treatment (Nominal $000s)**				
Component	Capital	Deferred	Expense	Total
AMI	162,814	2,229	20,819	185,862
CFS	15	6,102	2,796	8,912
CVR	21,758	1,201	3,902	26,861
DLC	17,913	615	942	19,470
EDW	6	4,548	5,617	10,172
ESB	996	5,327	4,208	10,531
MDMS	1,996	43,842	5,887	51,725
OMS	42	11,212	6,836	18,091
CE	9	-	8,403	8,412
Total	**205,549**	**75,077**	**59,409**	**340,035**
Note: Includes all applicable taxes, AFUDC and allocated PMO costs.				

Table 3 above include costs for: (1) Equipment; (2) Hardware; (3) Internal Labor; (4) Maintenance; (5) Miscellaneous; (6) Outside Services; (7) Software; and (8) AFUDC, as described in Section II.A.2 of the Business case. These include costs for products and services to be supplied by a number of third-party vendors. As detailed in Exhibit E, in selecting these vendors, the Companies' general default approach was to select vendors through the formal request for proposals ("RFP") process. In each case where a SGF Project vendor has been selected outside of the traditional RFP process, the benefit of the selection (i.e., reduced costs to customers and faster development of the Companies' Smart Grid initiatives) has outweighed the need for a formal bidding process. **Total SGF Project Implementation Costs by Cost Category and Component (Nominal $000)**

Component	Equipment	Hardware	Internal Labor	Maintenance	Misc.	Outside Services	Software	AFUDC	Total
AMI	81,750	1,560	43,484	4,860	501	51,938	-	1,769	185,862
CFS	-	-	1,250	1,056	67	6,254	-	286	8,912
CVR	2,059	71	14,190	3,195	101	4,858	1,559	828	26,861
DLC	7,977	-	1,063	855	38	9,487	-	51	19,470
EDW	-	-	2,019	4,448	56	3,468	-	180	10,172
ESB	-	505	1,657	1,600	56	4,518	1,985	210	10,531
MDMS	-	1,565	5,766	2,873	539	33,468	3,702	3,811	51,725
OMS	-	-	2,733	1,007	217	12,802	667	665	18,091
CE	-	-	2,045	-	90	6,277	-	-	8,412
Total	**91,785**	**3,701**	**74,205**	**19,893**	**1,666**	**133,070**	**7,913**	**7,801**	**340,035**
Note: PMO costs allocated to individual components									

Table 4 below provides a summary of the SGF Project total costs by cost category.

Total SGF Project Implementation Costs by Cost Category and Component (Nominal $000)									
Component	Equipment	Hardware	Internal Labor	Maintenance	Misc.	Outside Services	Software	AFUDC	Total
AMI	81,750	1,560	43,484	4,860	501	51,938	-	1,769	185,862
CFS	-	-	1,250	1,056	67	6,254	-	286	8,912
CVR	2,059	71	14,190	3,195	101	4,858	1,559	828	26,861
DLC	7,977	-	1,063	855	38	9,487	-	51	19,470
EDW	-	-	2,019	4,448	56	3,468	-	180	10,172
ESB	-	505	1,657	1,600	56	4,518	1,985	210	10,531
MDMS	-	1,565	5,766	2,873	539	33,468	3,702	3,811	51,725
OMS	-	-	2,733	1,007	217	12,802	667	665	18,091
CE	-	-	2,045	-	90	6,277	-	-	8,412
Total	**91,785**	**3,701**	**74,205**	**19,893**	**1,666**	**133,070**	**7,913**	**7,801**	**340,035**
Note: PMO costs allocated to individual components									

Table 4

B. PROJECT BENEFITS

As detailed in Section III of the Business Case, the customer benefits of the SGF Project generally fall into the following three categories: (1) quantified monetary Operational Benefits that benefit customers by reducing the revenue requirements used to set base rates; (2) quantified monetary Direct Customer Benefits that inure directly to customers, such as through adjustments in their energy use patterns that reduce consumption, as well as through energy cost or other adjustment clause mechanisms; and (3) Non-Quantified Benefits that cannot be reasonably quantified at this time.

1. Quantified Monetary Benefits

The Smart Grid platform enabled by the SGF Project will have an expected useful life of 20 years. As a result, the estimate of the immediately quantifiable benefits of the SGF Project is based on a 20-year project life (i.e., from 2017 to 2036). Table 5 below shows the value of those benefits on both nominal and present value terms discounted at the Companies' weighted average cost of capital.

SGF Project Quantified Benefits ($ Millions)		
	Nominal (Yrs. 1-20)	Present Value (Yrs. 1-20)
Advanced Metering Infrastructure	290	116
Customer Facing Solutions	150	54
Conservation Voltage Reduction	384	151
Direct Load Control	26	10
Outage Management System	17	7
Existing Internal Labor Offset	10	7
20-Year Total SGF Project Benefits	**877**	**345**

Source: "Ben Totals by Company" tab in Attachment 8

Table 5

The total quantified Operational Benefits and Direct Customer Benefits of the SGF Project on a standalone basis over the twenty-year life of the investment (2017-2036) is $878 million in nominal dollars and $345 million on a present value basis.

a. Operational Benefits

The benefits attributable to the AMI subproject (including benefits related to the MDMS, ESB and EDW subprojects), portions of the OMS subproject (i.e., related to outage operational efficiency) and the internal incremental labor offset are considered to be Operational Benefits, and are estimated at approximately $294 million in nominal dollars over the 20-year project life (from 2017 to 2036).

b. Direct Customer Benefits

The benefits attributable to the CFS, CVR and DLC subprojects, as well as other portions of the OMS subproject (i.e., related to value of service)[16] are considered to be Direct Customer Benefits estimated at approximately $584 million in nominal dollars over the 20-year project life (from 2017 to 2036).

2. Non-Quantified Benefits

In addition to the quantified monetary benefits, the SGF Project will deliver certain benefits that cannot be reasonably quantified at this time. For example, benefits such as reduced GHG emissions, reduced dependency on foreign imported oil and increased renewable economic growth will be gained but cannot effectively be quantified. Other benefits such as improved customer service are considered to be intangible. Still other benefits such as increased local distributed renewable energy cannot be quantified because the data to quantify them is currently missing and/or too expensive to attain for quantification. Regardless, these benefits are considered real and will help the State of Hawai‘i attain its 100% renewable energy goal.

C. PROJECT ECONOMIC ANALYSIS

In order to evaluate the overall financial impact of the SGF Project on a typical residential customer, the Companies have included an “economic analysis” in Section IV of the Business Case that nets the twenty-year SGF Project costs, ongoing expenses and post-in-service costs against its Operational Benefits and Direct Customer Benefits, taking into account the time-value of money. Unlike a traditional revenue requirements analysis, the economic analysis

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[16] The value of service benefit is based on the cost of electric service interruption to a customer (e.g., loss of revenue, loss of materials/inventory due to interruption of refrigeration, etc.)

models Direct Customer Benefits of the SGF Project as if they were Operational Benefits in order to simulate the financial impact of the SGF Project from a customer perspective.[17]

As indicated above, the SGF Project is scheduled to be implemented over a five-year period at a cost of $340 million. Once placed in service, the Companies estimate that an additional $345 million of ongoing costs will need to be incurred over the anticipated 20-year asset life to support and maintain the investment. Another $51 million of post-in-service costs will be incurred in connection with the accelerated depreciation of the Companies' existing non-smart meters. Although these ongoing expenses and post-in-service costs are not included for purposes of the SGF Project cost estimate, they are included for purposes of evaluating the economics of the SGF Project as a stand-alone investment. Accordingly, this economic analysis assumes a total 20-year economic cost of $736 million in nominal dollars ($340 million + $345 million + $51 million), and $413 million on a present value basis.

The stand-alone present value of the SGF Project costs, ongoing expenses and post-in-service costs ($413 million) netted against the SGF Project Operational Benefits and Direct Customer Benefits ($345 million) reflects a BCR of 0.84. The economic analysis indicates that over the 20-year life of the investment, the SGF Project will cost (net of Operational Benefits and Customer Benefits) a typical residential customer using 500 kWh per month on average $0.23/month at Hawaiian Electric, $0.35/month at Maui Electric and $0.20/month at Hawai'i Electric Light, with overall cost reductions beginning in the 2029-2030 timeframe.

[17] A traditional revenue requirements analysis of the SGF Project is provided in Exhibit G.

As shown in Figure 3 below, at Hawaiian Electric, the monthly economic impact on a typical residential customer will peak in 2022 at $1.73/month, transition into net savings in 2029 and result in peak savings of $1.59/month in 2036. At Maui Electric, the monthly economic impact on a typical residential customer will peak in 2022 at $1.71/month, transition into net savings in 2030 and result in peak savings of $1.15/month in 2034. At Hawai‘i Electric Light, the monthly economic impact on a typical residential customer will peak in 2020 at $2.39/month, transition into net savings in 2029 and result in peak savings of $2.35/month in 2036.

Monthly Economic Impact Analysis by Company for a Typical Residential Customer

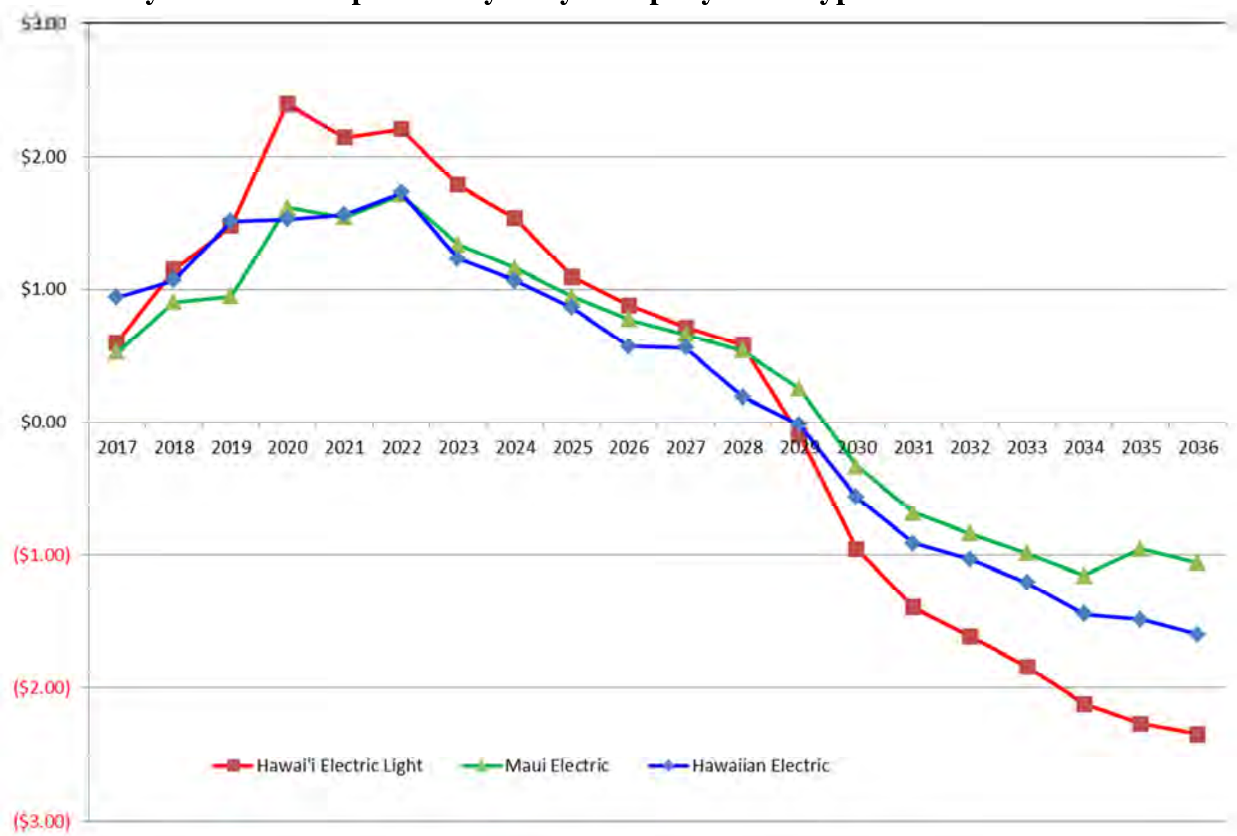

Figure 3

It is important to recognize that the SGF Project BCR does not include the non-quantifiable benefits such as those related to the Companies’ customer engagement activities or customer satisfaction derived from improved customer experience. Community benefits such as lower dependence on foreign oil, lower greenhouse gas emissions and increased clean energy economic growth are also not reflected in this ratio.[18] Further, the BCR does not consider the positive impact of the future opportunities to increase functionality, flexible system capabilities, and expansion of customer options provided by the SGF Project. For example, it is not possible to offer real-time pricing without the MDMS solution that is connected to an installed base of smart meters. In addition, the Smart Grid network delivers enhanced value to existing DR programs by providing near real time communications and usage information to customers and the utility. Other near term initiatives will build on the capabilities enabled by the SGF Project, including the DR Aggregator Contracts, DR Program Portfolio, DRMS Project, EV Time-of-use Rate Schedules, DER Time-of-use Rate Schedules, RTP Tariff, DA Project, DER Phase 1 and DER Phase 2. From a broader perspective, the SGF Project is one of the cornerstones that will enable Hawai‘i to achieve the 100% RPS by 2045 and confirm Hawai‘i’s continued leadership for the nation’s clean energy future.

IX. ACCOUNTING AND RATEMAKING TREATMENT

As indicated above, the Companies are requesting approval of the accounting and ratemaking treatment proposed to be applied to the SGF Project, as detailed in Exhibit F. The SGF Project is a complex project that consists of ten interrelated components consisting of traditional capital expenditures, which include construction and equipment, computer hardware and related software, software development, software services, and the significant

[18] Although many these benefits identified are societal and intangible, part of the benefits realization process will still be to assess customer satisfaction and experience with the Companies’ Smart Grid as a whole. This will be done through customer surveys and focus groups to continue to match customer tools to customer needs.

interconnection and integration to enable the full benefits of the project. In addition, due to its widespread impact, the SGF Project will require customer outreach and education activities to ensure successful adoption of the project. The SGF project also requires incremental support services from the PMO in order to ensure smooth, cost-effective and coordinated project execution.

The proposed accounting for the interrelated components generally follows the accounting for capital expenditure and software projects approved by the Commission in the past. In general, the cost of equipment and hardware and its related software obtained for the project, such as base hardware, middleware servers, virtual private network (VPN) infrastructure, tools hardware, imaging hardware and infrastructure changes, will be capitalized. 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 SGF Project 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".

However, because of the interrelated nature of the components, and the transformational nature of the SGF Project, atypical costs will be incurred, and the Companies are proposing accounting for those various components. Namely, the Companies are proposing to amortize the remaining book value of their existing non-AMI meters over a 10-year period, and also to defer the SGF Project Costs and Relevant Expenses (with accruals of appropriate carrying charges),[19] in the event that the Commission does not allow the Companies to seek cost recovery through the REIP Surcharge.[20]

X. REIP SURCHARGE COST RECOVERY

The application of the REIP Surcharge has been specifically tailored to address the cost recovery issues that can arise in connection with complex investments in renewable energy infrastructure, such as the SGF Project. As detailed in Exhibit G, the Companies are proposing certain measures to provide flexibility and tailor the application of the Surcharge to further address the unique nature of the costs and timing of the SGF Project.[21]

A. MODIFIED REIP FRAMEWORK

Among other things, the Companies' Application in this proceeding requests approval to recover the revenue requirements associated with the Capital Costs, Software Development Costs and Relevant Expenses through the REIP Surcharge as proposed in the Modified REIP Framework. As noted above, if the Commission does not allow the Companies to seek recovery through the REIP Surcharge, the Companies are requesting approval to defer of the SGF Project

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[19] The carrying charges would be accrued at the Companies' respective: (1) AFUDC rates from the time work commences on each respective Release until the in-service/go-live date of that Release; and (2) short-term debt rates from the in-service/go-live date of each respective Release until base rates that reflect the SGF Project Costs and Relevant Expenses take effect in the Companies' next respective rate cases.

[20] Updates of the Companies' Power Supply Improvement Plans ("PSIPs") will be filed on April 1, 2016. After that filing, the Companies intend to update the SGF Project Business Case to reflect the assumptions used in the updated PSIPs. The Companies have not yet quantified the carrying cost impact of the deferral alternative referenced above but intend to provide such quantification with the updated SGF Project Business Case.

[21] It should be noted that because the REIP Surcharge is a volumetric mechanism, recovering the costs of the SGF Project on a cents per kilowatt-hour basis may result in little or no contribution from customers who participate in Net Energy Metering because they are billed on net kWh. The Companies expect to work with the Commission, Consumer Advocate and other stakeholders in Phase 2 of the Distributed Energy Resources proceeding to address issues of appropriate recovery for all costs such that the SGF Project costs and benefits are more fairly and reasonably allocated to all customers.

Costs and Relevant Expenses until base rates that reflect the SGF Project Costs and Relevant Expenses take effect in each of the Companies' respective rate cases over the duration of the SGF Project and/or their first respective rate cases after the SGF Project has been completed.

The SGF Project would qualify for cost recovery under both the Modified REIP Framework and Existing REIP Surcharge. However, the Companies maintain that the Modified REIP Framework is the preferred mechanism for recovery, as the Consumer Advocate and the Companies have agreed and jointly requested the Commission to modify the REIP and the REIP Surcharge according to the Modified REIP Framework in Docket No. 2013-0141. The Modified REIP Framework provides for the surcharge accounting deferrals to be offset by the known and measurable operational net savings or benefits resulting from the SGF Project. Thus, recovering the net costs of the SGF Project (i.e., net of the quantified Operational Benefits) via the Modified REIP Framework would reduce the impact of the surcharge on customer bills.

B. PRE-IN-SERVICE/GO-LIVE EXPENSES

The complexity and scope of the SGF Project make it unlike other projects of smaller scale for which the Companies might apply for recovery through the REIP Surcharge. Thus, the Companies contend that cost recovery for the SGF Project should be approached in a flexible manner, with certain departures from treatment that would otherwise be applied under the provisions of the REIP Surcharge and staggered triennial regulatory rate review cycle. For example, a mechanism will need to be created to facilitate surcharge recovery of the substantial SGF Project-related expenses (e.g., Pre-In-Service/Go-Live and Customer Engagement Expenses) that will need to be incurred prior to the various subprojects being placed in service. The Companies are proposing to address this issue by including the budgeted Pre-In-Service/Go-

Live expenses for each year in the REIP Surcharge in the same year and recovering those expenses over a twelve month period.

The Companies believe it would be unfair and contrary to well-established principles of regulation for the Operational Benefits of the SGF Project to be passed to customers without allowing the Companies to recover the reasonable costs of achieving those benefits. Moreover, including the Pre-In-Service/Go-Live Expenses for each year in the REIP Surcharge and contemporaneously recovering those expenses over twelve months would be fair to customers as bills would reflect the cost of the various SGF Project components in the same general timeframe as when the components are providing benefits to customers. If the Commission is not inclined to allow the approach to recovering pre-in-service/go-live and customer engagement expenses proposed above, then the Companies propose in the alternative that the Pre-In-Service/Go-Live Expenses be deferred until their related in-service/go-live dates and included in the REIP Surcharge as part of the first adjustment after the in-service/go-live date.

C. DURATION OF SURCHARGE

With respect to the regulatory rate review cycle, due to the duration of the SGF Project timeline, it is conceivable that the SGF Project could overlap with one or more of the test years of the Companies' future general rate cases. In the interest of simplicity and transparency, the Companies are proposing to address this issue by continuing to include the SGF Project costs and quantified Operational Benefits through the REIP Surcharge until rates take effect in their first respective rate case(s) after the SGF Project has been completed. To ensure against double-counting, the Companies plan to remove project costs and benefits from the revenue requirements of any intervening rate cases. The alternative to this approach would be to incorporate the surcharge amounts into rates during each rate case test year that overlaps the SGF

Project schedule, and then re-commence surcharge recovery after such test year(s) until either: (1) the SGF Project is completed; or (2) another rate case test year overlaps with the SGF Project schedule.

D. BILL IMPACT

The net impact of including the: (1) Post-In-Service/Go-Live Costs; (2) Pre-In-Service/Go-Live Expenses; (3) Post-In-Service/Go-Live Ongoing Expenses; and (4) Operational Benefits, of the SGF Project in the REIP Surcharge is shown in **Unmerged SGF Project**
Estimated REIP Cost Recovery Surcharge (Monthly $ Per Customer)

Company	2017	2018	2019	2020	2021	2022	2023	2024
Hawaiian Electric	1.16	1.81	2.49	2.67	2.88	3.14	2.78	-
Hawai‘i Electric Light	0.63	1.57	3.21	4.43	4.30	4.42	-	-
Maui Electric	0.56	1.17	2.23	3.14	3.17	3.34	3.00	-

Table 6, below.

Unmerged SGF Project
Estimated REIP Cost Recovery Surcharge (Monthly $ Per Customer)

Company	2017	2018	2019	2020	2021	2022	2023	2024
Hawaiian Electric	1.16	1.81	2.49	2.67	2.88	3.14	2.78	-
Hawai‘i Electric Light	0.63	1.57	3.21	4.43	4.30	4.42	-	-
Maui Electric	0.56	1.17	2.23	3.14	3.17	3.34	3.00	-

Table 6

As shown above, the REIP Surcharge for the SGF Project (based on typical residential monthly usage of 500 kWh and the sales forecasts assumed in the Companies’ February 2016 Power Supply Improvement Plans) will peak in 2018 and decrease through 2021, after which time the relevant costs and benefits of the project will be moved into the revenue requirements used to set each Companies’ future base rates.

XI. WAIVERS

In order to facilitate the SGF Project implementation, promote smart meter customer adoption and help smooth the transition to smart meter service, the Companies are requesting waivers of G.O. 7 Rule 4.5(a) (adjustment of bills, generally), Rule 4.5(d) (back-billing) and

Rule 6.1(e) (in-service performance tests),[22] as well as the Companies' tariff Rule 11.A (meter test), Rule 11.B (adjustment of bills for metering error) and Rule 14.A.2.a (equipment furnished by the customer) provisions, during the SGF Project implementation period (2017-2021).

A. BACKBILLING OF SLOW METERS

G.O. 7 Rule 4.5(a) governs adjustment of bills and provides in part:

> Whenever a meter creeps or whenever a metering installation is found upon any test to have an average error of more than 2.0 per cent; or a demand metering installation more than 1.0 per cent in addition to the errors allowed under Accuracy of Demand Meters; and [sic] adjustment of bills for service for the period of inaccuracy shall be made in the case of over-registration and may be made in the case of under-registration. . . .

Tariff Rule 11.B similarly provides:

> Whenever a meter creeps or whenever a metering installation is found upon any test to have an average error of more than 2.0 percent; or a demand metering installation more than 1.0 percent in addition to the errors allowed under Accuracy of Demand Meters; an adjustment of bills for service for the period of inaccuracy shall be made . . . .

Pursuant to G.O. 7 Rule 4.5(b), adjustments due to slow meters are limited to the preceding three months.

G.O. 7 Rule 4.5(d)(1) and (2) further provide:

> 1. If the recalculation of billing indicates that an amount due the utility is equal to or in excess of amounts set forth . . . as minimum refunds, the utility may bill the customer for the amount due.
> 2. Each utility may establish a policy whereby the minimum sum . . . which it will commence billing for amounts due to under-registration is in excess of the amounts set forth . . . as minimum refunds. In such cases the

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[22] Pursuant to Docket No. 5088, Order No. 8373, filed June 17, 1985, the Companies were granted a waiver of G.O. 7 requirements relating to meter testing standards and were required to conform to the current ANSI code and related standards. See also Docket No. 2009-0004, *Decision and Order* dated July 29, 2010 (G.O. 7, as amended by Order No. 8373 in Docket No. 5088, requires electric utilities operating in the State of Hawai'i to conform to the current ANSI code and related standards).

> minimum sum established as the amount above which the utility will commence billing shall determine in all case of under-registration whether the customer will be billed for the amount due the utility because of under-registration.

The Companies propose to temporarily waive the back-billing provisions above for slow meters during the SGF Project implementation period. Specifically, the Companies propose to waive back-billing regarding discrepancies in smart meter billing as compared with a customer's legacy meter billing (i.e., slow legacy meters) only up to the point of smart meter installation.[23] From the point that service commences after smart meter installation, G.O. 7 Rule 4.5(a) and Rule 4.5(d), as well as Tariff Rule 11.B would again apply. The proposed waiver would not cover a situation where a customer was over-charged, in which case, the Companies will continue to follow the procedures set forth in the appropriate rules.

It is the Companies' position that this limited waiver would promote smart meter adoption and customer goodwill; would smooth the transition to smart meter service; and would promote administrative efficiency for the Companies, given: (1) that approximately over 450,000 meters are planned to be replaced; (2) the administrative resources required to quantify and effectuate the back-billing; and (3) the administrative resources required to provide customer support in response to back billing inquiries.

B. IN-SERVICE PERFORMANCE TESTS

G.O. 7 Rule 6.1(e) generally requires that:

> In-service performance tests must be made. . . . These tests may be made on the customer's premises or in the utility's meter shop. However, it is recommended

[23] The Companies intend to utilize a third-party service, Detectant, to perform analytics on post-installation data from each smart meter and compare against historical use data to determine whether a removed meter was operating outside of tolerances (slow or fast).

> that meters associated with instrument transformers, or phase shifting transformers, or those having mechanical contact devices, be tested on the customer's premises. Tests made for other purposes, such as request or referee tests shall not be considered as in-service performance tests, except those tested under a periodic test schedule.[24]

Tariff Rule 11.A.1 similarly states: "Meters and associated metering devices will be tested and adjusted . . . ."

The Companies are proposing a waiver of the in-service performance test requirements cited above for all meters (standard and non-standard) during the five-year SGF Project implementation.

Currently, the Companies utilize an annual statistical sampling test plan in accordance with American National Standards Institute ("ANSI") C12.1 § 5.1.4 (Standards for In-Service Performance), pursuant to which the Companies divide their installed meters into homogeneous groups by manufacturer and then further by meter/device type (single phase, polyphase and demand). The sample size for each manufacturer's device lot is determined by ANSI Z1.9. Each company then selects meters from each device lot in an amount equal to the sample size dictated by ANSI Z1.9. Over the past three years, the total sample test lot size for Hawaiian Electric, Maui Electric and Hawaiʻi Electric Light has averaged 1840, 941 and 707, respectively.[25]

The Companies anticipate a smart meter adoption rate of 96%, resulting in the installation of over 450,000 meters over the SGF Project implementation. Therefore, the impact of the

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[24] G.O. 7 Rule 6.1(e)(1).

[25] To be clear, the Companies are not proposing that ANSI standards cease to be applied to meter tests, the Companies are only proposing that the requirement to test meters be suspended during the SGF Project implementation.

requested waiver on actual meters tested as a percentage of installed meters would be small. In addition, it would be a more efficient use of meter shop resources to focus on smart meter installation rather than on in-service performance testing of legacy meters that will soon be retired.[26]

C. METER SOCKET REPAIR

Tariff Rule No. 14.A.2.a requires that the customer furnish, install, and maintain certain equipment required for service connection and meter installation on the customer's premises, including meter sockets:

> The applicant or customer shall furnish, install and maintain in accordance with the Company's requirements all conductors, service switches, fuses, meter sockets, meter and instrument transformer housing and mountings, switchboard meter test buses, meter panels and similar devices, irrespective of voltage, required for service connection and meter installations on the customer's premises. Detailed information will be furnished by the Company upon request. The customer or applicant should also comply with all applicable National, State and County electrical codes.

The Companies are requesting a waiver of this provision only insofar as it would require a residential customer[27] to pay for repairs to a meter socket that: (1) is damaged in the course of a smart meter installation; and/or (2) does not appear to be damaged prior to the smart meter

[26] In the process of installing smart meters, the Companies will remove existing meters, which will then either be retired or warehoused for future use if needed to supply NSM service tariff customers. The vast majority of removed meters will therefore be retired and sold for scrap. The Companies will store those makes and models of legacy meters that are known to have high failure rates for a period of 120 days and will test them upon customer request.

[27] Replacement of the meter sockets generally will not present C&I customers with the same hardship as residential customers. In addition, C&I customers make up a small percentage of total installations. Therefore, any delays caused by needing the C&I meter socket replacements will not have the same potential impact on the AMI subproject schedule. Accordingly, the Companies are not seeking a waiver of Rule 14.A.2.a as to C&I customers.

installation, but is found to be damaged during the installation.[28] This alternative is being proposed in order to avoid the potential implementation delay and safety issues that could occur in the event of needed meter socket replacement. It also alleviates the additional cost to residential customers of approximately $1,000 per replacement. This proposed policy will also encourage adoption of this important technology.

The SGF Project cost estimate includes approximately $1.4 million for the replacement of these residential meter sockets.[29] If, when the SGF Project is near completion, it appears that sufficient budgeted funds are available to repair the meter sockets not covered by this requested waiver, the Companies propose to use those funds to pay for those repairs on the customers' behalf. The Companies believe this proposed method of addressing customer meter socket issues during the smart meter rollout is a fair way to facilitate customer adoption, and the Companies anticipate that a relatively small percentage of customers will require this assistance.

In Docket No. 2008-0175, Hawaiian Electric sought a project specific waiver of Tariff Rule No. 13, which would have required the customer to pay the cost for installation of underground facilities less estimated net salvage of the overhead facilities removed, to allow the Company to contribute part of underground line conversion costs. There, the Commission granted the ". . . project specific waiver of Rule 13 of its tariff ("Rule 13") to allow HECO to contribute [,]" noting that the project was consistent with the intent of Hawaiian Electric's policy

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[28] In a situation where the residential customer's existing meter socket is visibly damaged prior to the smart meter installation, the Companies will attempt to work with the customer to repair the meter socket at the customer's expense.

[29] <u>See</u> Business Case.

on underground lines to convert existing overhead lines to underground facilities[30] and that the company's contribution to the project ($50,832) was not significant when compared to its overall plant in service balance.[31]

In the case of the SGF Project, the proposed Rule 14 waiver would facilitate customer adoption of a key transformational technology and would not result in a significant impact on the overall project cost. Thus as in Docket No. 2008-0175, the Commission should similarly grant the proposed waiver of Rule 14.

XII. PROPOSED TARIFF

The Companies are requesting approval of the proposed NSM Service tariff provided as Exhibit H. As the AMI subproject is implemented and smart meters are installed at customers' premises, "standard service" will be metered through smart meters. Customers will also be offered the option to opt-out of standard service in advance of the installation by paying a monthly fee of $15.30 as described in Exhibit H Attachment 1 and enroll in the NSM Service program by submitting the enrollment request form, provided as Exhibit H Attachment 2. Under the NSM Service Tariff, customers who elect to enroll in the NSM Service program will have their meters read manually and will not be eligible for certain programs, including: (1) TOU rate options, RTP rate options or any other time-interval dependent programs; (2) DER programs; or (3) any programs that would normally require service through a smart meter.

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[30] Hawaiian Electric also indicated that it "has proactively addressed the Legislature's clearly expressed concern that the community's desire for underground utility facilities be facilitated, if and to the extent that the undergrounding can be done at a reasonable cost. The proposed cost sharing is a reasonable solution for the conversion of the existing overhead lines to underground facilities." Docket No. 2008-0175, *Decision and Order* filed November 13, 2009 at 6.
[31] See id. at 11.

XIII. REPORTING

Enterprise infrastructure projects such as the SGF Project are similar in concept to the CIS project approved in Docket No. 04-0268, the HRSS project approved in Docket No. 2006-0003, the Budget System Replacement project approved in Docket No. 2010-0339 and the ERP/EAM Implementation Project that is pending approval in Docket No. 2014-0170. In those dockets, the Companies agreed to certain reporting requirements in order to facilitate the expeditious approval of the applications in those proceedings. Similar reporting requirements would be appropriate in this instance. Accordingly, the Companies propose the following:

(1) The Companies agree to file: (a) status reports with the Commission and the Consumer Advocate on an annual basis;[32] and (b) notification letters, if and when there is a significant change in either the scope or cost of the Project, from the baseline scope or cost identified in this Application as a result of completion of the Project.[33]

(2) The Companies will file within 90 days of the in-service/go-live date of each SGF Project Release, a cost report that provides the appropriate details that state whether the costs of the Release were capitalized, deferred or expensed, along with summary supporting documentation.

(3) The Companies will also perform reporting on the recovery of costs through the REIP Surcharge as described in Exhibit G.

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[32] The SGF Project annual status report will contain the key project performance indicators by subproject, including but not limited to project progress metrics (e.g., meters planned versus installed, percent complete), project risks and mitigations and key target dates / milestones planned versus accomplished.

[33] The term "significant" as used in this requirement is defined as an increase or decrease in scope beyond the scope identified as a result of the Project or an increase or decrease in projected cost of the program (as stated in the Application or most recent estimate of the project cost) of over 10%. This filing is not intended to result in any immediate regulatory action and should only be considered as a notification requirement.

XIV. STATUTORY PROVISION OR AUTHORITY

The approvals in this Application are requested pursuant to Sections 269-6, 269-7, 269-16, 269-16(b)(2)(D), 269-91 through 96 of the Hawai‘i Revised Statutes (“HRS”); Sections 6-61-74 and 6-61-86 of the Rules of Practice an Procedure Before the Public Utilities Commission, Title 6, Chapter 61 of the Hawai‘i Administrative Rules (“HAR”); the *Decision and Order* issued on December 30, 2009 in Docket No. 2007-0416; D&O 18365; D&O 32052; Order 32735; and Paragraphs 1.2.e., 2.3(g)(2), 4.5(a), 4.5(d) and 6.1(e) of G.O. 7.

XV. FINANCIAL STATEMENTS

The Companies’ capitalization as of December 31, 2015 was provided on pages 18-20 (Hawaiian Electric) and pages 21-23 (Maui Electric) of Hawaiian Electric’s and Maui Electric’s application *For Approval of the Issuance of Unsecured Obligations and Guarantee*, filed February 29, 2016, in Docket No. 2016-0057, and on pages 11-16 in Exhibit B and Attachment R to Exhibit B to Hawai‘i Electric Light’s application *For Approval to Commit Funds in Excess of $2,500,000 for the Purchase of the Hamakua Energy Partners Power Plant and the Related Financing Plan and Accounting Treatment; to Recover Certain 2016 Plant Addition Costs through the Rate Adjustment Mechanism ("RAM") Above the RAM Cap, and to Include Fuel Costs in Hawai‘i Electric Light Company, Inc.'s Energy Cost Adjustment Clause*, filed February 12, 2016, in Docket No. 2016-0033, and is incorporated by reference herein pursuant to HAR § 6-61-76.

The Companies’ audited financial statements for the year ended December 31, 2015 (audited by PricewaterhouseCoopers LLP), included in Hawaiian Electric’s and HEI’s Securities and Exchange Commission Form 10-K dated February 23, 2016, were filed with the Commission on February 25, 2016, and are incorporated by reference herein.

The Companies' latest available balance sheet and income statement for the 12 months ending December 31, 2015 (unaudited) were filed with the Commission on February 23, 2016, and are also incorporated by reference herein.

XVI. IMPACT OF NEXTERA ENERGY MERGER

Attached as Exhibit I, is NextEra Energy SGF Project business case under the scenario that the merger of NextEra Energy and the Hawaiian Electric Companies is approved ("Merged Business Case"). Under the Merged Business Case, the scope of the SGF Project remains generally the same.

At a high level, the primary differences between the Merged Business Case and the unmerged business case are related to the SGF Project costs and deployment schedule. The $318 million level of costs included in the Merged Business Case is approximately $22 million (or 6%) lower than the unmerged business case costs of $340 million. The major drivers of these differences in costs are that: (1) AMI implementation is accelerated from 5 to 3 years: (2) supply chain costs for some equipment and system integrator costs are reduced by 5%; (3) some solutions used by FPL can be leveraged (e.g. MDMS and EDW); and (4) key FPL personnel are can provide additional expertise and thus reducing execution risks. The Companies have already been working with NextEra on the SGF Project and accordingly, much of their lessons learned have already been incorporated into the SGF Project.

In sum, the Merged Business Case demonstrates that the merged Companies can bring Smart Grid benefits to Hawai'i's residents faster, at a lower cost, and with lower overall risk.

XVII. CONCLUSION

Wherefore, the Companies respectfully request that the Commission issue a decision and order approving:

(1) the SGF Project Costs of approximately $340 million, including $206 million of Capital Costs, $75 million of Software Development Costs and $59 million of Expense;

(2) The accounting and ratemaking treatment proposed to be applied to the SGF Project, including:

(a) a commitment of funds in excess of $2,500,000, excluding customer contributions for the Capital Costs under Rule 2.3(g)(2);

(b) deferral of the Software Development Costs pursuant to the Companies' Software Accounting Policy and D&O 18365 and accrue AFUDC during the deferral period, and/or, if the Commission deems such approval to be necessary, to commit expenditures in excess of $2,500,000 for the Software Development Costs pursuant to Rule 2.3(g)(2);

(c) depreciation of the Capital Costs in accordance with the Companies' Capital Project Accounting Policy including depreciation of the smart meters over a 20-year period;

(d) amortization of the Software Development Costs in accordance with the Software Accounting Policy over a 12-year period;

(e) amortization of the remaining book value (currently estimated at approximately $51 million) of the Companies' existing non-AMI meters over a 10-year period; and

(f) recovery of the revenue requirements associated with the Capital Costs, Software Development Costs and other Relevant Expenses including: (i) Pre-In-Service/Go-Live Expenses; (ii) Post-In-Service/Go-Live Ongoing

Expenses; and (iii) Customer Engagement Expenses through: (A) the REIP Surcharge as proposed in the Modified REIP Framework; or in the alternative, (B) the Existing REIP Surcharge, until base rates that reflect the unrecovered SGF Project Costs take effect in each of the Companies' first respective rate cases after the SGF Project has been completed, with:

i. relevant costs and Operational Benefits of the SGF Project included in the REIP Surcharge on a quarterly basis and trued-up annually;

ii. a carrying charge applied at the Companies' respective short-term debt rates to the SGF Project Costs and Relevant Expenses (including any deferred depreciation and amortization expenses that the Companies may incur prior to the onset of REIP Surcharge recovery) between the in-service/go-live date of each respective Release and the commencement of REIP Surcharge recovery for each Release;

iii. a return at the Companies' respective AFUDC rates on the unrecovered Capital Costs and deferred Software Development Costs from the commencement of REIP Surcharge recovery until base rates that reflect the unrecovered amounts take effect in the Companies' respective rate cases; and

iv. contemporaneous inclusion of the Relevant Expenses in the REIP Surcharge as incurred, or in the alternative, deferral for subsequent recovery of the Pre-In-Service/Go-Live Expenses and Customer Engagement Expenses until the in-service/go-live of each respective Release;

(g) in the alternative, if the Commission does not allow the Companies to seek recovery through the REIP Surcharge, deferral of the SGF Project Costs and Relevant Expenses until base rates that reflect the SGF Project Costs and Relevant Expenses take effect in each of the Companies' respective rate cases over the duration of the SGF Project and/or their first respective rate cases after the SGF Project has been completed, with accrual of appropriate carrying charges; and

(3) waivers of:

(a) G.O. 7 Rule 4.5(a), Rule 4.5(d)(1) and Rule 4.5(d)(2), and Tariff Rule 11.B of each company so that the Companies can temporarily suspend back-billing for slow meters during the SGF Project;

(b) G.O. 7 Rule 6.1(e) and Tariff Rule 11.A.1 of each company, so that the Companies can temporarily suspend the annual in-service performance testing for all meters during the SGF Project; and

(c) Tariff Rule 14.A.2.a, insofar as it would require a residential customer to pay for repairs to a meter socket that: (1) is damaged in the course of a smart meter installation; and/or (2) does not appear to be damaged prior to the smart meter installation, but is found to be damaged during the installation; and

(4) the NSM Service tariff.

DATED: Honolulu, Hawai'i, March 31, 2016.

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

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

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

Exhibit A

Hawaiian Electric Companies'

Smart Grid Strategy and Roadmap

Smart Grid Strategy and Roadmap

March 2016 Update

Forward

In 2014, the Hawaiian Electric Companies[1] filed a *Smart Grid Roadmap and Business Case* with the Commission,[2] proposing to implement Smart Grid at all three of our operating utilities, on the five islands we serve. As noted in the *Commission's Inclinations*,[3] ". . . the Commission believes Hawaii should be poised to lead the world in the development of advanced grids. . . ." Our Smart Grid will help modernize our power grids, enable integration of more renewable energy, reduce outage times, increase the efficiency of our operations, reduce costs, further public policy goals and deliver benefits to our customers. This *Smart Grid Strategy and Roadmap* ("Smart Grid Plan") supersedes that prior filing, and provides a framework to more comprehensively "connect the dots" between the many components, projects and associated Commission applications needed to execute our Smart Grid vision by investing in new technologies to deliver the benefits of a smart grid to customers.

The evolution of Smart Grid technology is driving unprecedented changes in the energy industry in general and Hawai‘i in particular. Implementing a Smart Grid efficiently and cost-effectively is a challenging endeavor. Smart Grid brings major changes for the Companies, our customers and the State of Hawai‘i. Our plan reflects our understanding of the complexity of this undertaking and our efforts to lead the way on energy produced from natural resources such as solar, wind and hydropower, which are constantly replenished. This Smart Grid plan is considered to be a "living document" that will be updated periodically in accordance with the Companies' Smart Grid vision, increasingly refined assumptions, applicable technology improvements and the constantly evolving needs and wants of our customers, including reliability, affordability, safety and peace of mind.

This document is specifically intended to provide our policymakers, third-party partners and technology suppliers a more detailed understanding of the Hawaiian Electric Companies' Smart Grid vision, strategy, roadmap and related projects. Collectively, these initiatives represent one of the largest coordinated efforts we have ever undertaken. Throughout its progressive implementation, Smart Grid will play an increasingly pivotal role in Hawai‘i's energy future, and the Companies look forward to working with the Commission, the Consumer Advocate and other stakeholders to make Hawai‘i's Smart Grid a leading model within the industry, while demonstrating how it will benefit customers, enable more renewable energy and improve customer service.

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

2 Filed March 17, 2014 in Docket 2008-0303.

3 See pages 10-11 of *Appendix A: Commission's Inclinations on the Future of Hawaii's Electric Utilities* to Decision and Order No. 32052, filed April 28, 2014 in Docket No. 2012-0036, referred to herein as the "Commission's Inclinations."

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SMART GRID STRATEGY AND ROADMAP OVERVIEW

Smart Grid is a key component of the Hawaiian Electric Companies' business strategy and ongoing transformation into a next generation energy company that is committed to improving the way energy is delivered using new technologies that benefit customers. Our Smart Grid is defined as the integration and application of real-time monitoring, advanced sensing, communications, analytics and control that enable the dynamic flow of both energy and information to accommodate existing and new forms of energy supply, delivery and use in a secure, reliable and efficient electric power system from generation source to customers.[1]

Our Smart Grid vision is to provide an increasingly intelligent and automated electric system that utilizes technology advancements to leverage capabilities in telecommunications, computing, sensing and controls for transmission and distribution to all service locations via a multi-direction flow of energy and information. Smart Grid will enable our customers and us to control and make more informed and timely energy decisions. We will utilize these technology advancements to better meet customers' expectations, the State's energy policy objectives, communities' energy demands, and our overarching responsibility to provide safe, reliable and secure electric service. Smart Grid will modernize our power grids, enabling a more seamless integration of renewable energy, increasing reliability and efficiency, protecting the environment, lowering costs, and providing customers with greater visibility of their energy usage, as well as more options for energy choices.

The value proposition for a Smart Grid is unique in that many of its related benefits – such as lower dependence on imported fuel, lower greenhouse gas ("GHG") emissions and increased clean energy economic growth – are community based, complex and/or difficult to readily quantify. There are also hard benefits that are not only quantifiable but also realized as a result of implementing our Smart Grid strategy. Hence, we present an overarching compelling case that appeals not only to those who desire direct benefits but also for those who desire to improve our community and environment. As a result, the strategy for realizing our Smart Grid vision is focused on five strategic themes: (A) customer empowerment; (B) distributed energy resource ("DER") integration[2]; (C) power grid efficiency, reliability and resiliency; (D) safety and workforce efficiency; and (E) innovation, information and connectivity. These themes will be supported by one or more of the projects presented herein; and conversely, some of our Smart Grid-related projects will support multiple Smart Grid strategic themes.

Building a Smart Grid in Hawai‘i will not be accomplished in a single project effort, but will evolve over time, growing and layering capabilities and functionality that increasingly deliver incremental value to customers. The need for such an iterative and phased approach adds further complexity to the Smart Grid value proposition, as each additional component that is

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[1] As defined by the North American Electric Reliability Corporation ("NERC") Smart Grid Task Force ("SGTF") report: *Reliability Considerations from the Integration of Smart Grid*, dated December 2010, Executive Summary, available at http://www.nerc.com/files/SGTF Report Final posted vl.l.pdf.

[2] DER includes distributed generation ("DG"), distributed storage, demand response ("DR"), energy efficiency and electric vehicles ("EV"s).

layered over the foundational platform leverages existing capabilities, thereby increasing the value of the infrastructure (including renewable energy infrastructure such as customer-sited DG) already in place. When viewed in isolation, some Smart Grid-related projects may not have a positive business case.

However, when taken in their entirety, the overall bundle of benefits and capabilities enabled by Smart Grid supports an overall estimated positive business case that will increase flexible capabilities and lower costs in the long run. The estimated benefit-to-cost ratio of the Smart Grid to our customers is approximately 1.4. Over the next twenty years, the Companies estimate that Smart Grid will result in $221-$271 million in benefits net of costs (net present value) to customers or between $418 and $511 per customer over the same period.

In the near term, the platform upon which we will build our Smart Grid begins with the base installations planned through the Smart Grid Foundation Project ("SGF Project"), which has already been guided by the results of various pilot projects, peer energy company lessons learned, our strategic partnership with Silver Springs Networks, Inc. ("SSNI") and our Smart Grid Initial Phase demonstration project ("Initial Phase") on O'ahu with approximately 5,047 customers. Other Smart Grid-related near-term initiatives that further build upon this base include the Companies':

- DER Aggregator Contracts;
- Demand Response ("DR") Program Portfolio;
- DR Management System ("DRMS") Project;
- EV Time-of-use Rate Schedules;
- DER Time-of-use Rate Schedules;
- Real-Time Pricing ("RTP") Tariff;
- Distribution Automation ("DA") Project;
- DER Phase 1; and
- DER Phase 2.

Over the longer-term, our Smart Grid efforts will transition from the current "Base Stage" of implementing the foundation into an "Enhancement Stage." In the Enhancement Stage, innovations and new capabilities will be identified, evaluated and layered upon our then-existing Smart Grid infrastructure utilizing our maturing process methodology to address this ever-changing landscape. We will continue to embrace our role as an enabler of clean energy from sources that help reduce our environmental impact and trusted energy advisor for the State and people of Hawai'i.

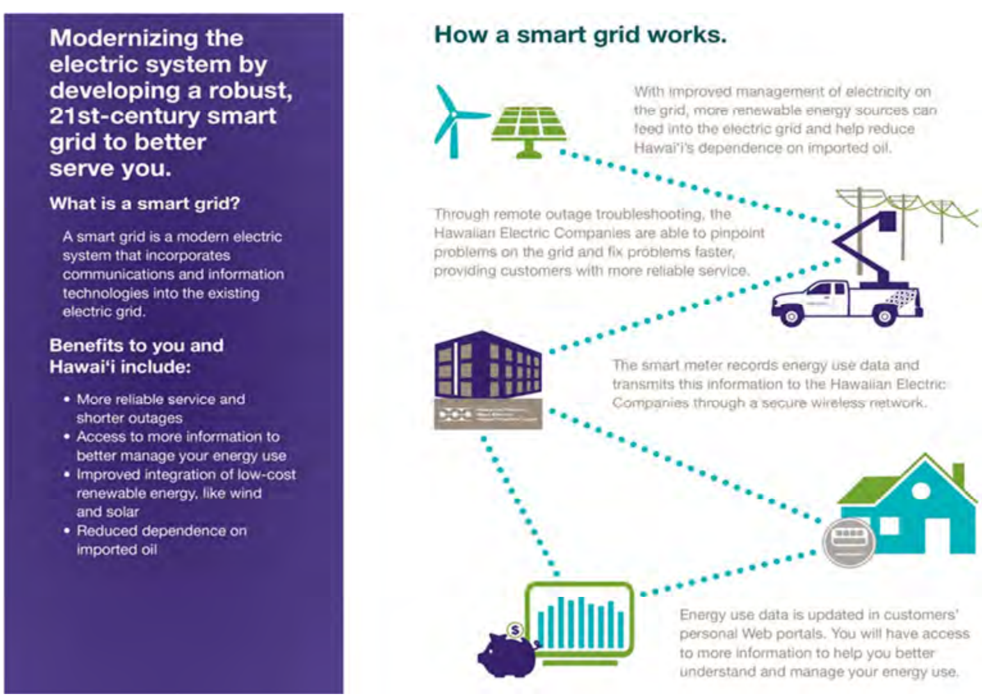
I. What is a Smart Grid? How does it work? Why do we need it?

The energy industry as a whole is faced with many challenges in a world where our energy future is changing. There are many key issues that need to be addressed – including worldwide climate change, energy independence and infrastructure security. These overall high-level challenges are similar for us here in Hawai'i. In fact, we lead the nation in certain areas of small localized energy generating resources, which means that we must modernize our power grid to accommodate more integration of renewables and provide greater flexibility to manage DG from variable energy sources that can only produce power under certain conditions. A key attribute of a next generation energy company is the ability for customers to have more options and control over their energy use and/or generation. By building a smarter energy infrastructure, a safe, secure and economically feasible Smart Grid can increase our ability to address these rapidly changing needs.

So what exactly is a Smart Grid? A Smart Grid is a more dynamic and secure power grid that gives customers more control, greater flexibility and more choices while also responding to outages more quickly, seamlessly connecting to clean energy sources and securing the grid from attacks. This adds increased levels of information exchange and visibility, and possibilities for greater control at the transmission and distribution levels, focusing on how, when and where energy is generated and used. Information is gathered through a multi-directional digital communications network that is added to the existing power grid infrastructure – the wires, poles and substations. Some of this equipment is upgraded to better handle the changing flow and nature of energy on the power grid while other equipment, such as “smart meters,” “advanced inverters,” and/or “smart storage” are added to increase visibility and understanding of energy production and use, and provide more efficient, effective and reliable control of the modernized power grid. All of these enhancements increase the “intelligence” of information on the grid, and increase our ability to respond to changing conditions.

So how exactly does a Smart Grid work? Figure 1 below provides a high-level overview of how our Smart Grid will work. The base premise is that there will be a network of networks that connect up many smart devices located at the transmission and distribution levels, and ultimately at each customer’s premises. This connectivity provides the ability to exchange information and provide controls to optimize the flow and use of energy.

Figure 1 - How Smart Grid Works



So why do we need a Smart Grid? A Smart Grid will provide the technological foundation needed to address Hawai'i's, unique energy challenges. Due to the physical nature of our State – isolated in the middle of the Pacific Ocean and separated by islands with unique topography – we are challenged with a relatively high cost of energy because electric power cannot currently be transmitted among neighboring islands or from surrounding systems as is done on most of the U.S. mainland. This geographic isolation makes balancing supply and demand more difficult, since we cannot rely on neighboring utilities to help address short-term imbalances or take advantage of regional differences in energy markets to help reduce costs to customers.

Our State's physical location, however, does enable us to be a leader in renewable energy. At the end of 2015, 23% of our customers' energy needs were met by renewable resources – more than twice the percentage of just five years ago and well on the way to achieving Hawai'i's 2045 renewable portfolio standards ("RPS") goal of 100%.[3] Much of that renewable energy is from variable resources (i.e., distributed solar photovoltaics ("PV"), wind and run of the river hydroelectric). In fact by the end of 2015, more than 14% of our residential customers were generate a majority of the electric energy providing power for their individual homes from their private rooftop PV systems. This renewable generation benefits both our customers and the environment. At the same time, this accomplishment presents challenges in system resiliency, reliability, safety and efficiency: Solar and wind renewable generation are variable and there is lack of visibility and control over distributed PV (e.g., actual PV generation information is not shared with the utility); and customer-generated solar energy, for the most part, is not efficiently distributed around the entire distribution network.

A Smart Grid is needed to help manage these complexities. The evolution of Smart Grid technologies is paving the way for new products and services that will help customers manage their energy use while providing the utility with the necessary information and control to ensure on-going service quality and reliability. Smart Grid technologies also enable greater visibility by grid operators and customers into how the power grid is functioning. Grid operators can better see how customers or groups of customers are interacting with the grid. With increased roof-top PV and growth in EVs, customers are becoming "prosumers" – i.e., both producers of energy being placed onto the power grid as well as consumers of energy being taken from the grid. The deployment of smart devices will modernize the power grid by enabling multi-directional data interchange and control between field, back office and customer devices. Timely and actionable information will allow grid operators to better monitor local power grid conditions to improve reliability and operational efficiencies such as circuit voltage optimization that will flow through to ultimately lower customer bills. These capabilities will lower costs, expand customer choices, increase reliability and optimize integration of DER.

Over the past decade, the concept of a "smarter grid" has been identified in numerous federal, state and regulatory forums as being a critical capability and the foundational functionality necessary to achieve energy policy goals and objectives. For example, the Energy

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3 See *The Hawaiian Electric Companies' 2009 Corporate Sustainability Report*, page 6, and the Hawaiian Electric Companies' news release dated March 3, 2016 titled, *"Hawaiian Electric Companies report record high renewable energy use."*

Policy Act of 2005 identified Smart Grid as a foundational capability necessary to support energy efficiency goals.[4] Additionally, Title XIII of the Energy Independence and Security Act of 2007 identified the specific capabilities the power grid must demonstrate in order to achieve the federal policy goals of modernizing the U.S. power grid. This is intended to make improved digital information available to customers to empower customer choice, facilitate the integration of renewable DER, improve grid reliability and resiliency, and support the integration of EVs.[5]

In Act 109 of 2014, the Hawai‘i Legislature also identified the need for grid modernization, and in turn, directed the Commission to consider grid modernization in its planning and evaluate the potential of smart technologies to mitigate technical barriers of integrating large amounts of DG.[6] Integration of DER, along with cost-effective, utility-scale renewable generation from wind and solar, will be required in order to achieve Hawai‘i's RPS goal of 100% by 2045,[7] as well as support Hawai‘i's GHG reduction objectives.[8]

The Commission's Inclinations, the Commission further articulated its perspective on the vision, business strategies and regulatory policy changes needed to best serve Hawai‘i's energy consumers, including specific guidance on strategies, planning and projects to create a modern transmission and distribution network.[9] Collectively, these energy policies have guided the development of our Smart Grid vision.

II. Our Smart Grid Vision

The Hawaiian Electric Companies' Smart Grid vision is to enable our customers and us to control and make more informed and timely energy decisions by providing an increasingly intelligent and automated electric system that utilizes technology advancements to leverage capabilities in telecommunications, computing, sensing and controls for transmission and distribution to all service locations via a multi-direction flow of energy and information.

Our Smart Grid vision is a key component of our business strategy and plans. It directly supports our efforts to transform our Companies into a next generation energy company.[10] The Companies' strategy for developing and deploying a Smart Grid uses a phased and iterative approach, recognizing that core infrastructure and basic functionality must be put in place first (i.e., Base Stage). Moreover, the Companies recognize that power grid modernization is a complex, network-centric process and will need to be accomplished not only in stages over time but also in conjunction with other initiatives we are undertaking to transform all aspects of electric service.

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[4] Title II, Section 921; Title XII, Section 1251-1252, Energy Policy Act of 2005.
[5] Title XIII-Smart Grid, Section 1301, Energy Independence and Security Act of 2007.
[6] Act 109, 2014 Haw. Sess. L. ("Act 109").
[7] See HRS § 269-91.
[8] See Act 234, 2007 Haw. Sess. L., Greenhouse Gas Emissions Reductions.
[9] See generally the Commission's Inclinations.
[10] See Hawaiian Electric's 2015-2020 Strategic Transformation Plan, filed as Attachment 1 to the response to CA-IR-376 in Docket No. 2015-0022. Also summarized and referenced in Applicant's Exhibit-65, pages 5-8.

While our Smart Grid vision and development strategy support ambitious federal and State policy objectives, we also recognize that building a Smart Grid is a process of evolution in addition to implementation. Some of the technologies needed to realize our vision are still in the early stages of development. While many show great promise, more investigation and evaluation is required to ensure that the desired results can be reliably and cost-effectively achieved. In order to address this ever-changing landscape of innovation, we have put in place a continuous process for the identification and evaluation of technologies that will help us develop and deploy our Smart Grid over the next 20 years. As a result, our Smart Grid will be developed and deployed through a number of related yet separate initiatives and projects over this timeframe. The first implementation of projects in the near term (e.g., the Initial Phase, DRMS, DER policy framework, and the SGF Project) are part of the Base Stage and is foundational to the success of the subsequent projects/initiatives.

Our Smart Grid vision and strategy includes deploying technologies that provide high customer value. This vision and strategy also includes identifying and evaluating "best-fit/least cost" technologies that provide solutions to achieve policy objectives that may not immediately, or on a stand-alone basis, have positive business cases, but deliver community benefits nonetheless.[11]

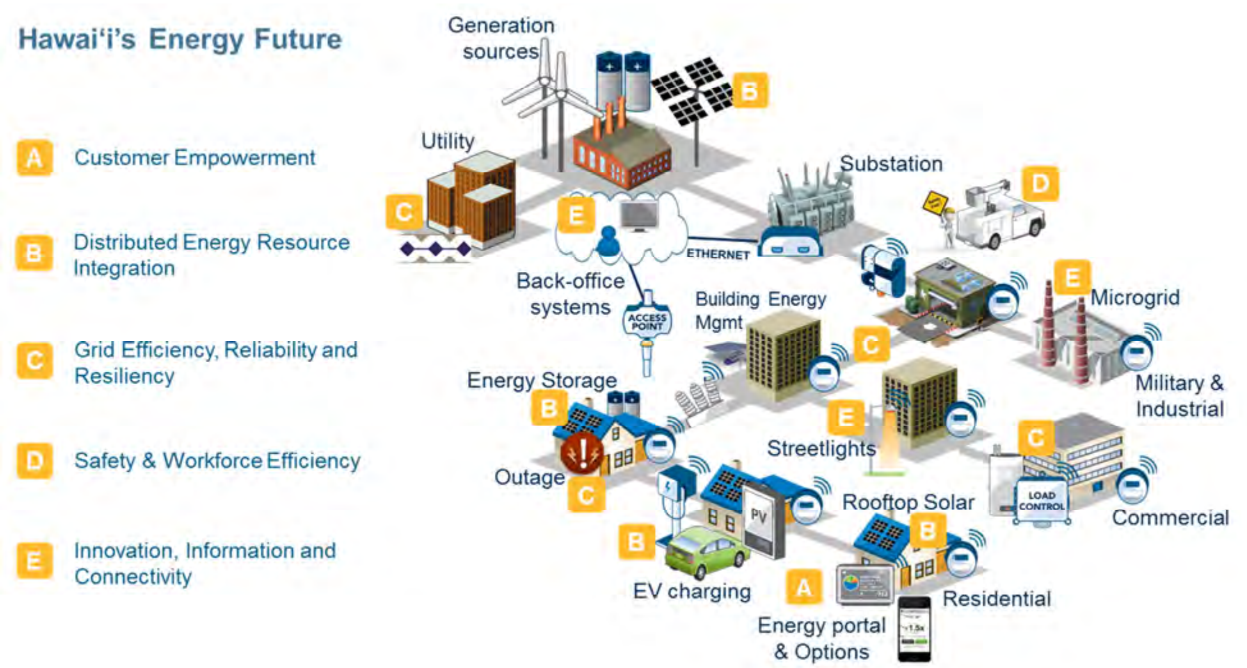
III. Key Strategic Themes to Accomplish our Smart Grid Vision

Our Smart Grid vision is focused on obtaining and implementing specific Smart Grid solutions that provide the capabilities defined within the following five key strategic themes: (A) customer empowerment; (B) DER integration; (C) power grid efficiency, reliability and resiliency; (D) safety and workforce efficiency; and (E) innovation, information and connectivity.

Figure 2 below provides a high-level view of a modern and fully integrated Smart Grid and its associated key strategic themes. It illustrates the role of our Smart Grid in enabling Hawai'i's energy future.

[11] In Decision 07-04-043, the California Public Utilities Commission discussed the consideration of "non-quantifiable" or "difficult to quantify" benefits in connection with San Diego Gas & Electric's advanced metering infrastructure ("AMI") application. See id., pages 21-22, 70-71.

Figure 2 - Smart Grid Strategic Themes for Hawaii's Energy Future



This section provides details about the specific capabilities and example deliverables within each strategic theme. Additionally, in Section VI, our Smart Grid near-term roadmap is laid out by strategic theme and its corresponding timeframes.

A. Customer Empowerment

The "Customer Empowerment" strategic theme encompasses key capabilities that will enable our customers to be aware of relevant energy conditions, and to participate in, monitor and control their energy usage/generation while reducing their carbon footprint and energy costs. This is also a key component of our Companies' overall strategic vision.[12] In order to accomplish this, the following capabilities are required:

- Timely access to and use of energy information: Provide access to energy information that encourages customers to understand their usage/generation, participate in programs that lower their energy costs and provide suggestions on what they could do to optimize their energy use;

- Timely access and feedback to power grid conditions: Develop capabilities that provide customers with access to near-real-time information that promotes customer situational awareness about relevant power grid conditions and outages (e.g., automated outage visibility by meter pings, estimated restoration times, potential mobile customer reporting of issues);

[12] The Hawaiian Electric Companies' vision statement is, "Empowering our customers and communities with affordable, reliable, clean energy."

- Multiple viable customer options: Implement technologies that increase power grid agility and enable increased offerings of relevant customer products and services (e.g., DR programs, community solar, EV charging stations to applicable customer segments); and

- Customer advocacy and trust: Establish trust with our customers through greater transparency of energy information, and be an advocate of our customers' interests as they relate to developing cost-effective and interoperable smart consumer technology solutions and services by promoting Smart Grid standards development and market adoption that drives competition and reduces costs for our customers.

B. Distributed Energy Resource Integration

The DER Integration strategic theme encompasses key capabilities that will increase and improve integration and interconnection services that facilitate the use of fair and affordable DER while maintaining grid stability, reliability, efficiency and safety. In order to accomplish this, the following capabilities are required:

- Collaborative DER policy framework development and institutionalization: Work collaboratively with stakeholders and the Commission in order to set the appropriate policy framework that fairly and affordably increases integration of DER;

- Timely access to and use of granular distribution and service location grid information: Increase information granularity and visibility of distributed energy in order to support hosting capacity analysis and transmission and distribution planning;

- Responsive power quality mitigation: Investigate and deploy appropriate energy storage solutions that support the integration of variable renewable energy resources that mitigate power quality issues while providing power grid support (e.g., frequency regulation);

- Capture and harness excess energy generation: Investigate and deploy appropriate energy storage solutions that support the efficient integration of variable renewable energy resources by storing excess generation for economic use at a future time;

- Real-time visibility and control of DER: Investigate and deploy a system that allows for the real-time visibility and control of DER (e.g., customer, energy company and/or aggregator); and

- Electrify transportation: Implement technologies that promote the electrification of transportation as a good source of DER via the use of potential virtual power plants.[13]

[13] See, e.g., A. Zuborg. *Unlocking Customer Value: The Virtual Power Plant,* Power World 2010,ABB/Ventyx, available at http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/ABB_Attachment.pdf.

C. Grid Efficiency, Reliability and Resiliency

The strategic theme for "Grid Efficiency, Reliability and Resiliency" encompasses key capabilities that will improve and optimize the performance, reliability, power quality and operational efficiency of the power grid. The following capabilities are required to accomplish this:

- Real-time visibility and utility control of grid assets: Implement automation at multiple layers of the power grid to increase visibility, utility control and performance of grid assets;
- Proactive and timely grid data analysis and modelling: Provide granular data analytics that support proactive modelling and understanding of the various factors that must be considered to make prudent investments in the power grid that meet customers' future energy needs;
- Real-time visibility to manage and control voltages at a granular level: Implement technologies that provide the capability to reduce line losses and increase power grid capacity and efficiency;
- Self-healing/autonomous grid controls: Increase power grid reliability by adopting and expanding smart technologies that can predict/prevent/reduce outages and align with appropriate North American Electric Reliability Corporation ("NERC") standards;[14] and
- Automated and enhanced grid resiliency: Implement security and outage management measures that improve power grid resiliency, protect against cyberattacks and can withstand natural disasters.

D. Safety and Workforce Efficiency

The "Safety and Workforce Efficiency" strategic theme encompasses key capabilities that will improve customer and employee safety, as well as workforce efficiency in the changing environment of a next generation energy company. Accomplishing this requires the following capabilities:

- Fully automate manual processes: Increase workforce safety by automating manual tasks and/or confirmation of no back feed of power on a line. Employ automation so that staff need not be exposed to electrical hazards;

[14] NERC (the North American Electric Reliability Corporation) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains and certifies industry personnel. NERC's area of responsibility spans the continental U.S., Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners and operators of the bulk power system, which serves more than 334 million people. Hawaiian Electric is not required to comply with NERC, but where applicable it is referenced as a utility best practice.

- Smart process automation: Increase safety by reducing and mitigating opportunities for operating errors via automated process steps and the use of smarter tools; and

- Re-focus workforce resources on critical tasks: Increase workforce productivity via the use of remote control and auto-sensing devices that can automate recurring processes and allow skilled workforce resources to focus on critical and complex tasks that require manual intervention.

E. Innovation, Information and Connectivity

The strategy for "Innovation, Information and Connectivity" encompasses key capabilities that will provide secure innovative information and communications environments to support flexible, scalable, and efficient multi-directional data and information exchange across the power grid. This theme requires the following capabilities:

- Innovative, robust and flexible Smart Grid architecture: Evaluate, promote and adopt a flexible, cost-effective and unified Smart Grid architecture that enables efficient information exchange, and innovation and technology improvements over time;

- Relevant, cost-effective and timely innovation: Partner, develop, implement and maintain highly reliable information systems and smart technologies that meet the future needs of a Smart Grid that supports market demand and prosumer choice;

- Timely massive data processing and analysis: Implement scalable "big data" warehousing and analytic solutions that promote efficient processing and storage of data to enable timely access to information for planning, modelling and simulations;

- Secured, interconnected and efficient network communications: Develop and implement telecommunications that provide connectivity across the power grid and enable the operation of an interconnected and integrated network of networks for transmission, sub-station, field and customer communications; and

- Data privacy resiliency: Heightened capabilities to protect and automatically respond to data privacy threats.

IV. Our Smart Grid Value Proposition

A key objective of our Smart Grid strategy is to modernize the energy company via the use of cost-effective technologies that provide significant customer value, while at the same time supporting policy objectives that potentially may not have immediate direct customer value, but may provide broader benefits to customers and society as a whole over time. It is important to note that traditional cost/benefit models will not be able to account for the total value derived from many Smart Grid investments because portions of the benefits are societal in nature – which includes addressing State priorities such as the 100% RPS mandate.

As indicated by the U.S. Department of Energy ("DOE") National Energy Technology Laboratory ("NETL"), benefits such as lower dependence on imported fuel, lower GHG emissions and increased clean energy economic growth are complex and often difficult to quantify. In addition, certain aspects of these benefits may not directly accrue to customers but rather to our broader community as a whole. However, when considered in their entirety, the overall bundle of benefits and capabilities enabled by Smart Grid supports a positive business case that will help to lower costs in the long run for all beneficiaries.[15] As additional projects and initiatives are developed, the Companies will continue to provide transparency into each application's business case.

With this in mind, our Smart Grid value proposition is presented as a portfolio of investments for modernizing grid capabilities, building upon each other over time. The overall Smart Grid benefits are broken down into three general categories: (1) direct customer benefits; (2) indirect customer benefits via operational improvements;[16] and (3) community benefits. Table 1 below provides a further breakdown of these benefit categories, along with examples of how the benefits will be achieved and what specific solution when implemented will deliver such benefits. Detailed descriptions and definitions for each solution are provided in Appendix A. The overall Smart Grid business case and cost per customer is also presented by solution below.

Table 1 - Smart Grid Benefit Categories

Direct Customer Benefits	Example Customer Benefits	Solution
Increase the value and relevance of electric products and services	• Enhance customer communications, data transparency and privacy, increase additional relevant products and services, and the speed/quality of existing electric services. This will help increase customer satisfaction and foster greater trust.	• CFS • AMI • CPO • DA • DR
Increase customer options	• Make available distributed energy options in generation and storage. This will help customers to maximize their energy investments (e.g., rooftop PV, EV).	• AMI • DER • DR
Reduce customer losses and improve reliability	• Avoid or reduce electric service disruptions that cause loss of revenue and inconvenience to customers.	• DA • AMI

[15] The DOE NETL published their study DOE/NETL-2010/1413, "Understanding the Benefits of the Smart Grid" on June 18, 2010. That publication explicitly outlines the fact that residential and commercial customer benefit-cost cases are not compelling and that they are only compelling when societal/community benefits are also considered. The benefits for Smart Grid are only positive when its value proposition is viewed from this overall perspective to unite all beneficiaries.

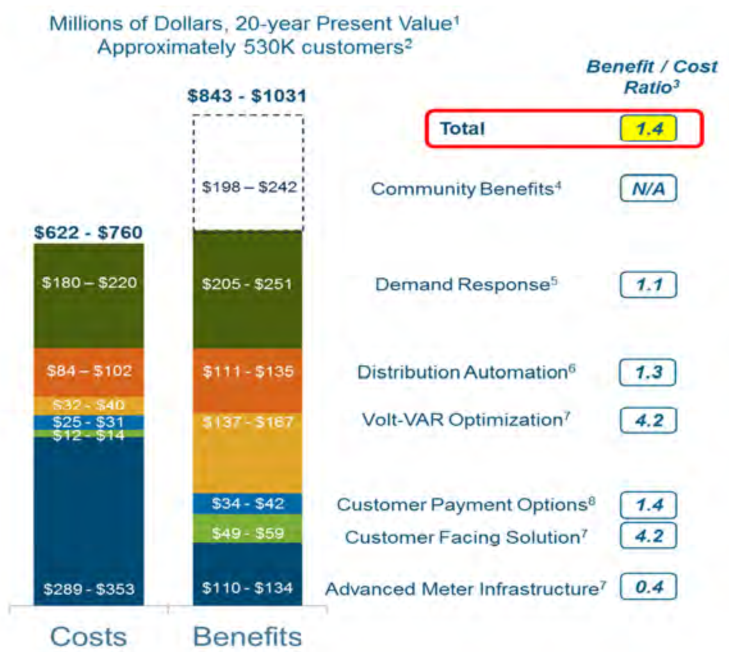
[16] The indirect customer benefits are also referred to as "Operational Benefits".

Lower customer bills	• Lower fuel consumption by optimizing voltage. • Ability to self-supply or grid supply customer-sited generation. • Ability to adjust energy usage through greater visibility and participation in cost-saving programs.	• VVO • DER • DR
Indirect Customer Benefits	**Example Operational Benefits**	**Solution**
Increase workforce safety and productivity	• Implement intelligent assets that reduce operational liability and improve efficiencies.	• DA
Avoid, reduce or defer capital investments	• Increase capacity utilization, enhance asset life and introduce new technologies that may replace the need for net new generating capacity.	• DER • DR
Reduce operating expenses and avoid revenue losses	• Restructure workforce by retiring old positions (e.g., meter readers) and by introducing more efficient processes that lower operating costs with automation. • Increase revenue protection capabilities that help reduce theft.	• AMI • DA
Reduce costly peak demand	• Introduce load shifting capabilities in order to balance variable (or as-available) generation with energy resources that can consistently generate reliable energy 24 hours a day.	• DR • AMI
Community Benefits	**Example Community Benefits**	**Solution**
Reduce carbon / GHG emissions	• Enable the integration of more renewable energy resources, making the generation of power cleaner and more efficient. • Increase energy efficiency, resulting in less fossil fuel generation and reducing our carbon footprint.	*All Smart Grid solutions provide community benefits
Promote energy independence	• Supporting our nation's and State's goal to reduce dependence on imported fuel by facilitating the increase in local renewable energy generation and electrification of transportation. This will help reduce geopolitical and economic risks.	
Promote clean energy economic growth	• Supporting our State's clean energy initiative for economic and associated job growth.	

Many of the Smart Grid solutions provide benefits to more than one benefit category; therefore, the overall Smart Grid business case is presented as costs and benefits by Smart Grid solution. Figure 3 below shows the overall projected Smart Grid costs and benefits. Our overall estimates as of the end of 2015 for the Smart Grid total costs (20-year present value) for all three service utilities is $622-$760 million ($1173-$1434 per customer) delivering $843-$1031 million ($1591-$1,945 per customer) in benefits. This results in an average overall benefit-to-cost ratio

("BCR") of 1.4. Aggregating these amounts, the Hawaiian Electric Companies estimate that Smart Grid will result in $221-$271 million in benefits net of costs (net present value) over the next 20 years, or between $418-$511 per customer in benefits net of costs (net present value) over the next 20 years.

Figure 3 - Overall Smart Grid Business Case



Notes:

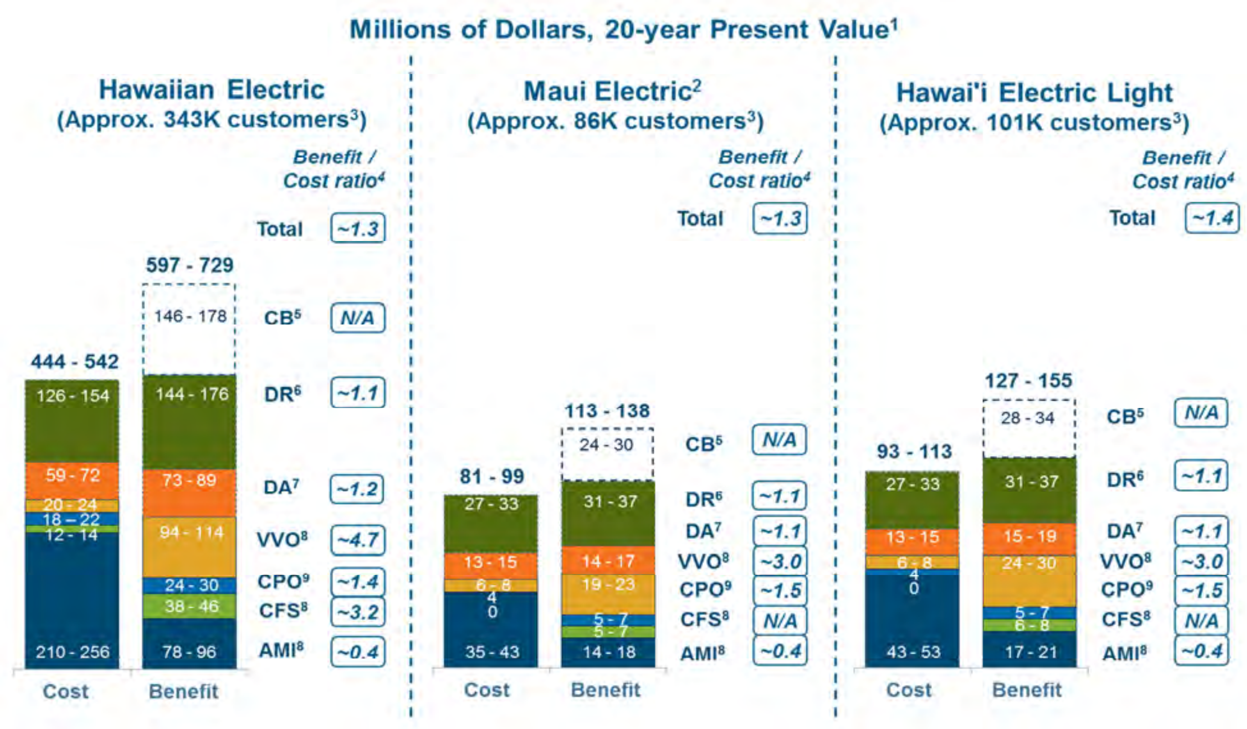
1 Present value is calculated using a discount rate of approximately 8.1%.
2 Estimated customer counts are based upon the projected 20-year forecast.
3 Benefit/cost ratios are based on the midpoint amounts of the associated ranges.
4 Community benefits are estimated at a very high level primarily based on the estimated energy savings of each solution translated into CO2 emissions reduction and a very small potential local economic growth in wage/salary jobs driven by the Smart Grid investments.[17]
5 DR benefits and costs are based on the recent DR Portfolio application filed on December 30, 2015 in Docket No. 2015-0412.
6 DA benefits include "value of service" benefits modeled as approximately $1.18/customer/minute at 15 minutes per company per year.
7 Volt/VAR Optimization, Customer Facing Solution, and AMI benefits and costs are based on the Companies' SGF Project Exhibit B to the accompanying Application.
8 Customer Payment Options benefits and costs are based on general national averages.

[17] NETL also cited examples of societal/community benefits related to GHG reductions, economic growth and reduction in foreign oil dependency. In their conclusion, when all benefits are taken into consideration, it cited example cases from EPRI and the West Virginia Smart Grid Implementation Plan as having BCRs of 4 or 5 to 1 and 6.7 to 1, respectively. The Companies have not quantified as high an overall BCR as more work needs to be done in partnership with local stakeholders in order to solidify and localize these estimates. The existing estimate for the community benefits utilize information from the Environmental Protection Agency's Green Power Network and the Department of Business, Economic Development, and Tourism's Actual and Forecast of Key Economic Indicators for Hawaii: 2011 to 2016.

Figure 4 below provides the same overall Smart Grid benefits and costs broken out by each operating utility. The spread between each operating utility is based on the planned physical location of specific utility assets in the field, the central allocation of back-end systems that are needed regardless of whether Smart Grid is implemented at Maui Electric or Hawai'i Electric Light, and the proportional customer spread for shared services.

The BCR for each operating utility ranges from approximately 1.3 to 1.4, and varies due to different operating cost structures, implementation scale, geography and forecasted energy costs. We estimate that over the next 20 years, Smart Grid will result in a net present value (i.e., benefits net of costs, discounted for the time-value of money) of $446–$545 per customer in at Hawaiian Electric; $325–398 per customer at Maui Electric; and $308–376 per customer at Hawai'i Electric Light.

Figure 4 - Overall Smart Grid Business Case by Operating Utility



Notes:

1 Present value is calculated with discount rate of approximately 8.1%. Numbers will not tie due to rounding.
2 Includes Maui, Moloka'i and Lana'i.
3 Estimated customer counts are based upon the projected 20-year forecast.
4 Benefit/cost ratios are based on the midpoint amounts of the associated ranges.
5 Community benefits are estimated the same as previously stated.
6 DR benefits and costs per overall is split between utilities using 70-15-15.
7 DA benefits include "value of service" calculated the same as previously stated.
8 Volt/VAR Optimization, Customer Facing Solution, and AMI benefits and costs are based on the Companies' SGF Project Exhibit B to the accompanying Application.
9 Customer Payment Options benefits and costs is split between utilities using 70-15-15.

While there are components of Smart Grid that deliver fewer quantifiable benefits than costs (i.e., components with a benefit-to-cost ratio of less than 1.0), it is important to take into account the non-quantifiable benefits and the overall Smart Grid portfolio of capabilities. Some base components such as AMI are considered foundational and therefore, may not have a positive business case by themselves but are required in order to enable the future capabilities needed for our Smart Grid. For example, to deliver certain DR programs, such as real-time pricing (RTP), AMI is needed to deliver RTP schedules in a timely and cost-effective manner. Similarly, the AMI network delivers enhanced value to existing DR programs by allowing for near real-time communications and usage information to the energy company and customers alike; it is leveraged to provide network connectivity for more than just the smart meters.

V. Our Smart Grid Development and Approach

At the heart of our Smart Grid is an extensive and secured multi-directional "network of networks" that is expandable, extensible and capable of evolving as new smart technologies are developed over time.[18] It will include advanced sensors and distributed computing technology that will not only improve the efficiency, reliability and safety of power delivery and use, but also unlock the potential for entirely new services and improvements to existing ones. The multi-directional Internet Protocol version 6 ("IPv6") communications infrastructure will support not only near-term applications, but also unanticipated applications that will arise in the future.[19] This results in a Smart Grid platform of integrated capabilities and functionality as illustrated in Figure 5 below. It further emphasizes that our Smart Grid development and approach must also be able to grow and adapt over time, especially given the rapidly evolving customer needs and technological innovations.

With this in mind, our Smart Grid development and approach leverages and integrates many capabilities via a solid platform that is coordinated and standardized through proactive architecture and design. This allows for a structured process methodology in which new innovations can be introduced, tested and utilized effectively as implementations progress. Our premise is to avoid technology incompatibility and potential stranded assets due to rapid technological changes, as well as to ensure that the rapid change that Smart Grid brings can be successfully innovated, tested, demonstrated, implemented and institutionalized.

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[18] "Network of networks" is defined by Christine Hertzog in the "Smart Grid Dictionary", 6th edition published on October 2014. It refers to a network comprised of smaller, heterogeneous public and private networks that connect to each other, and is meant that planners must identify potential relationships between networks and design solutions that leverage these synergies. This approach encourage creative use and reuse of resources for multiple purposes instead of single-use applications, and are especially important when dealing with complex systems and networks like Smart Grids.

[19] IPv6 is the most recent version of the communications protocol standards that provides identification, location and traffic of "things" on a network. This definition is broadly summarized from, William Stallings' article called *"IPv6: The New Internet Protocol"* published in the IEEE Communications Magazine, July 1996 issue.

Figure 5 - Our Smart Grid Platform

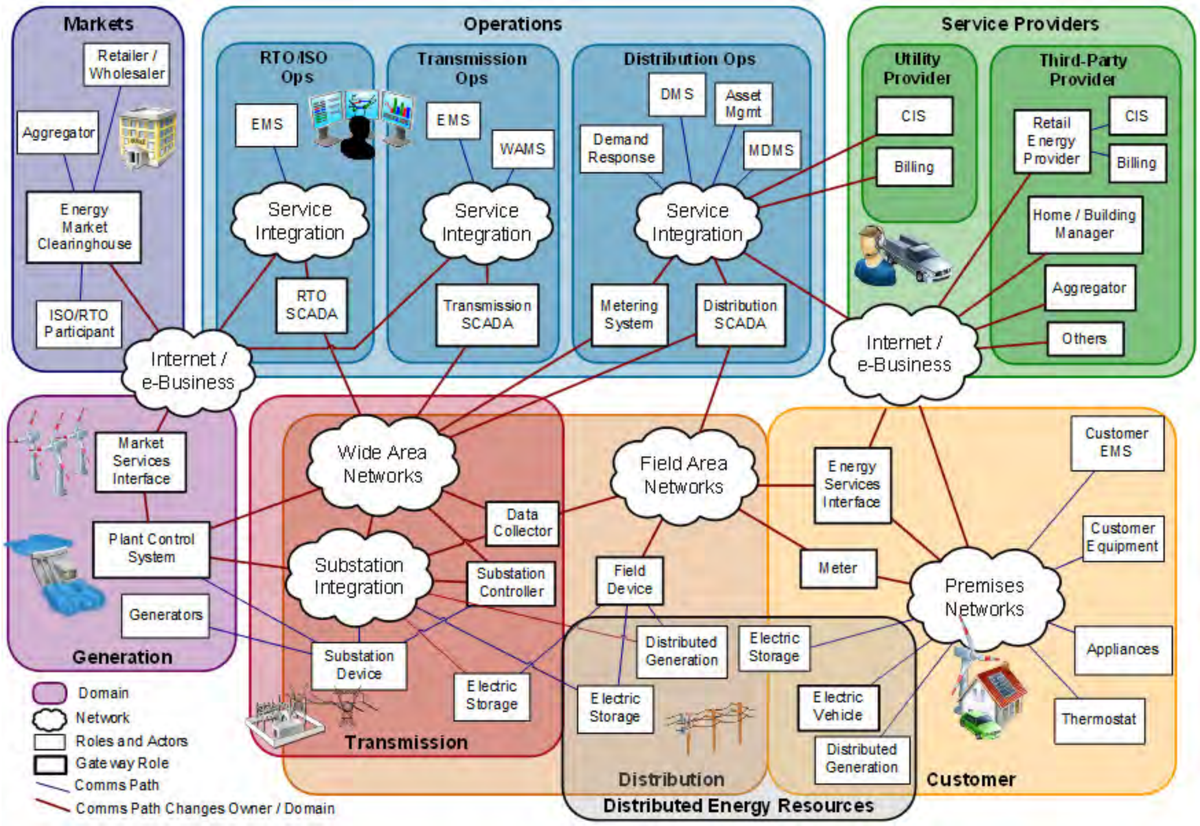
A. <u>Guiding Principles for Smart Grid Architecture and Design</u>

In order to ensure our Smart Grid investments have lasting impact and use, we have defined the following guiding principles that help frame and inform our decision making processes for our integrated Smart Grid architecture and design:

- Deliver a consistent, easy to understand and engaging customer experience;
- Implement proven technologies that are competitive, stable and reliable;
- Innovate in selected focus areas via strategic partnerships and collaborations;
- Monitor results, benchmark and learn from others;
- Leverage common infrastructure for broader use;
- Utilize and support industry standards that are relevant for Hawaiʻi; and
- Ensure a safe, secured and protected data environment.

By broadly applying these guiding principles, the Companies will be able to build a Smart Grid that modernizes the energy company to be more cost-optimized, flexible and responsive to customer needs. In addition, the Companies subscribe to the National Institute of Standards and Technology ("NIST") standards for establishing our Smart Grid architecture. NIST provides an integrated view of the general reference model and framework in which the relationship between the applicable generation, transmission, distribution and customer elements are shown in Figure 6 below:

Figure 6 - NIST Smart Grid Framework v3.0



Further details on our Smart Grid architecture, as aligned with energy industry based standards from NIST, the Institute of Electrical and Electronics Engineers ("IEEE") and Electric Power Research Institute ("EPRI") are provided in Appendix B.[20]

B. Overall Process Methodology

We have developed a measured, thoughtful and detailed approach to iteratively identify, test, evaluate, select and implement Smart Grid technologies that will deliver reliable, cost-effective products and services that customers value. This approach includes strategically partnering with SSNI, a leader in Smart Grid applications and networks, as well as working with other utilities that have implemented or are in the process of implementing their Smart Grids to identify, understand and adopt best practices and leverage related industry experience.[21] We

[20] NIST Smart Grid references can be found at http://www.nist.gov/smartgrid/ (primarily for framework, green button, and cybersecurity components). EPRI's Smart Grid references can be found at http://smartgrid.epri.com/ (primarily for distribution automation, reliability cost of service and CVR verification). IEEE Smart Grid references can be found at http://smartgrid.ieee.org/ (primarily for technical standards and long range technology road-mapping).

[21] Detailed level interactions have been carried out with five utilities – Oklahoma Gas and Electric (OG&E), Commonwealth Edison (ComEd), Florida Power and Light (FPL), Sacramento Municipal Utility District (SMUD) and Kauai Island Utility Cooperative (KIUC) – each of which use Smart Grid technologies similar to the what we are considering to implement in our service territories. They provided helpful and valuable discussions, exchanged

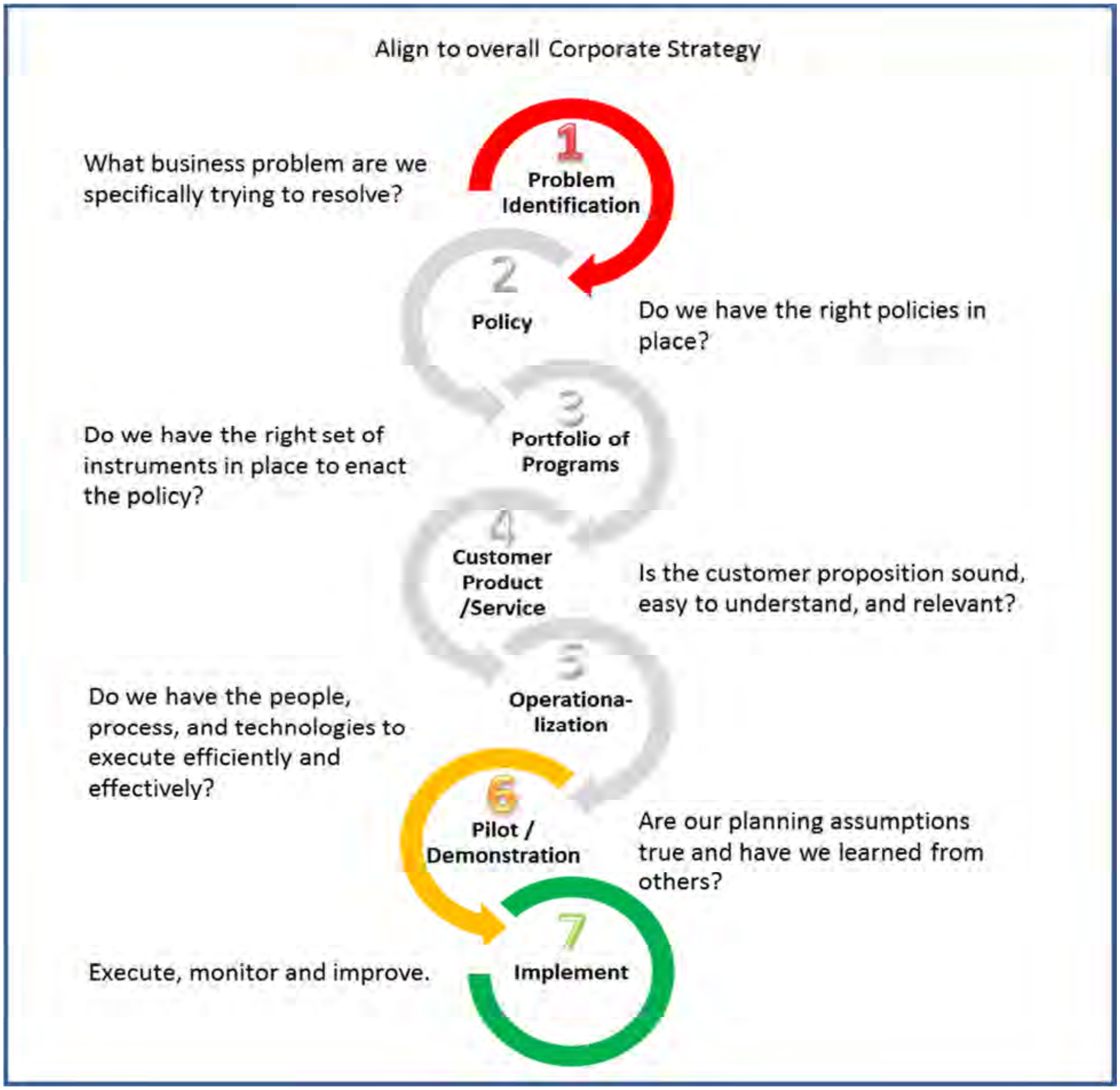
have also conducted, are conducting and/or will conduct Smart Grid technology demonstration projects within our service territories to more closely evaluate available technology solutions that will best deliver long-term value for our customers.[22]

The mix of both certain and developing solutions requires that we have a robust process methodology that will allow us to not only implement sound Smart Grid technologies that can be leveraged over time, but to also be able to successfully evaluate and forecast what the future will bring. This involves an iterative and inter-connecting process as defined in Figure 7 below. Ideally, these steps would be executed in sequential order. However, it is possible that the discovery and setup phase which includes steps to address policy, the portfolio of programs, customer product/service and operationalization (two to five) highlighted in gray, may be executed iteratively and simultaneously depending on the circumstances at the time and the level of third-party stakeholder involvement.

ideas and shared best practices. These were then applied in the execution of the Smart Grid Initial Phase, through which the Companies have now gained a better understanding of, and confidence in, the commercial maturity and performance of Smart Grid technologies, systems, operations, maintenance, organizational processes and customer engagement requirements that will be needed to successfully build our Smart Grid.

[22] The past and present demonstration projects include the JUMPSmart Maui Demonstration, Greater Maui Project and Department of Energy Renewable & Distributed Systems Integration Maui Smart Grid. The participants include Japan's New Energy and Industrial Technology Development Organization (NEDO) and U.S. Department of Energy (DOE), Hawaiian Natural Energy Institute (HNEI), Silver Springs Networks, Hitachi, Fonius, Pepco Holdings, Inc., Standard Solar, Silver Springs Networks, Maui Electric and Hawaiian Electric. The technologies evaluated under the demonstration projects included distribution management system ("DMS") and micro-DMS system to aggregate and control DER, 200 AMI meters and supporting communications network, customer home gateways and automated distribution network circuit switches. The projects include the Ulupono Grid Resiliency Pilot, PV Impact Analysis, DVI EDGE Product Development demonstration and Hawaii Energy's (a customer-funded energy conservation and efficiency program) Smart Grid Implementation Project. These projects are intended to demonstrate applications of new technologies like Fault Current Indicators ("FCI") for improved distribution network monitoring and control, advanced smart inverters to control grid-connected PV, advanced DR and EV charging management systems to help mitigate DER integration), new advanced data analytics and power engineering/distribution network modeling tools and in-home devices to allow customers to integrate and monitor home energy use and use an interactive web portal for access to Hawaii Energy's various energy efficiency applications. Partners and industry stakeholders include Ulupono Initiative, DBEDT, MetaTech, HNEI, DVI Grid Solutions, Hawaii Department of Defense, IBM, Hawaiian Electric, PACOM, and Hawaii Energy.

Figure 7 – Overall Process Methodology and Steps



The result of this overall process methodology is reflected in the Smart Grid roadmap presented in Section 7 below, which depicts both components that are already planned for implementation, as well as those that are still being tested and evaluated.

C. Engaging Our Smart Grid Customers

We believe a proactive, transparent and sustained communication effort to educate and engage our customers is critical to the success of achieving our Smart Grid vision. Our efforts to be relevant and engaging to our customers underscore our commitment to continually improve customer service, modernize the power grid and integrate distributed renewable energy. We intend to proactively engage customers about installing smart meters and other advances that give them more information and control over how they use their energy, share information about other Smart Grid benefits, and address concerns about safety, security and privacy. Key to this is helping customers understand that, at its core, Smart Grid technology will offer them more information than ever before about their energy use and generation, and give them tools and programs to help make decisions about their energy choices that complement their lifestyles; be it to be more environmentally green, to help manage their energy use, or to simply understand what options they have available to them.

Our customer communication program is based on tested and proven industry best practices, and is customized based on research conducted in Hawai'i on how to best reach/interact with our customers. Our approach seeks to engage our customers with information tailored to their specific needs and questions. Working with trusted third-party groups, we plan to engage customers in direct conversations to most effectively reach out to them. Taking the lessons learned from our Initial Phase, we have found that being transparent from the start and preserving customer choices up front are critical to maintaining our customer's trust.

Our efforts to engage our customers – indeed, all our stakeholders – will be guided by four fundamental communication guidelines:

1. Proactive: Anticipate stakeholder needs and develop approaches to meet those needs.
2. Collaborative: Work with stakeholders to design and improve the experience, products, and services they receive.
3. Responsive: Respond promptly and transparently to all inquiries.
4. Flexible: Expect and accommodate continual process and communication improvements.

While researching other Smart Grid implementations, and during our own Initial Phase demonstration, we found that our customers and the news media consistently raised concerns about three issues: (1) the safety of smart meters and radio frequency emissions; (2) security of the communications infrastructure; and (3) privacy of customer data. We have diligently identified industry experts and related research so that we can better address these and other concerns raised by our customers and the media. We intend to provide our customers with access to experts and the available educational information on these three issues.

1. Safety

Safety is our highest priority. Studies indicate all Silver Spring Networks-enabled devices present an extremely low-level of radio frequency exposure when compared to the regulatory limits established by the Federal Communications Commission (FCC) for safe operations. In our own local analysis, we have found that our Initial Phase smart meters transmit for only a fraction of the day for short durations and actual radio frequency emissions are actually less than commonly used devices such as cell phones and microwave ovens.

2. Security

We take the security of our communications and information technology systems very seriously. Maintaining secure systems is an ongoing process. Modern Smart Grid systems, such as the system we plan to implement, incorporate proven security applications. We have incorporated the latest and most advanced security enhancements available to-date and will continue to do so as it further improves over time.

3. Privacy

We are committed to ensuring the privacy of our customers' data. Our customer privacy policy includes the following commitments:

- We will not sell, rent, or license your personal information.
- We treat customer information as confidential, consistent with legal and regulatory requirements.
- We will only share your information with your consent, or as provided for in our privacy policy.
- We require any person or organization we share data with to protect customer information.
- We do not allow any person or organization acting on our behalf to use our customer information for their own marketing purposes.

4. Communications Plan

As part of our customer communications plan, we will proactively utilize the following tactics, tools, and capabilities to engage our customers:

- Community outreach;
- Customer education;
- Government relations;
- Third-party engagement;
- Media relations;
- Customer research;
- Employee engagement; and
- Customer service support.

We understand how important it is to remain flexible and to adapt to the dynamic needs of our customers, throughout our Smart Grid journey. That is why we have developed many different strategies and methods for communicating with our customers and engaging them in meaningful dialogue throughout the entire Smart Grid implementation.

D. Partnerships and Third-Party Collaborations

In order to best serve our customers, our community and the environment as a whole, we believe that it will take the overall joint efforts of many to deliver on the promise of Smart Grid benefits. Smart Grid is a very broad and complicated concept that can be more successful when strategically aligned and tactically coordinated. This is especially true in Hawai‘i's communities that face unique challenges and opportunities. In recognition of this, we intend to work closely with Hawai‘i's policy makers, our strategic partners and third-party collaborators in developing suitable Smart Grid solutions, leveraging investments and solidifying standards that will deliver value to our State. Collaborative discussion and alternative viewpoints on emerging standards and solutions are encouraged, in order to produce and implement the best solutions in a timely fashion. Joint efforts to coordinate customer solutions are also needed in order to foster healthy competition and maximize value to customers.

In 2013, we formed a strategic partnership with SSNI, an industry leader in Smart Grid technology. Over the last decade they have proven their mettle in implementing Smart Grid, and have successfully installed their Smart Grid mesh technology that currently serves over 23 million homes and businesses at more than 30 utilities. Together, we have planned and designed the appropriate blend of Smart Grid applications that is expected to deliver on our vision. SSNI also helped us with our Initial Phase, in which we have successfully implemented our target AMI solution to approximately 5,000 homes and businesses on O‘ahu.

A number of third-party stakeholders have expressed their support for Smart Grid. Copies of documentation of some of that support are provided as Attachment 1.

VI. Our Smart Grid Roadmap

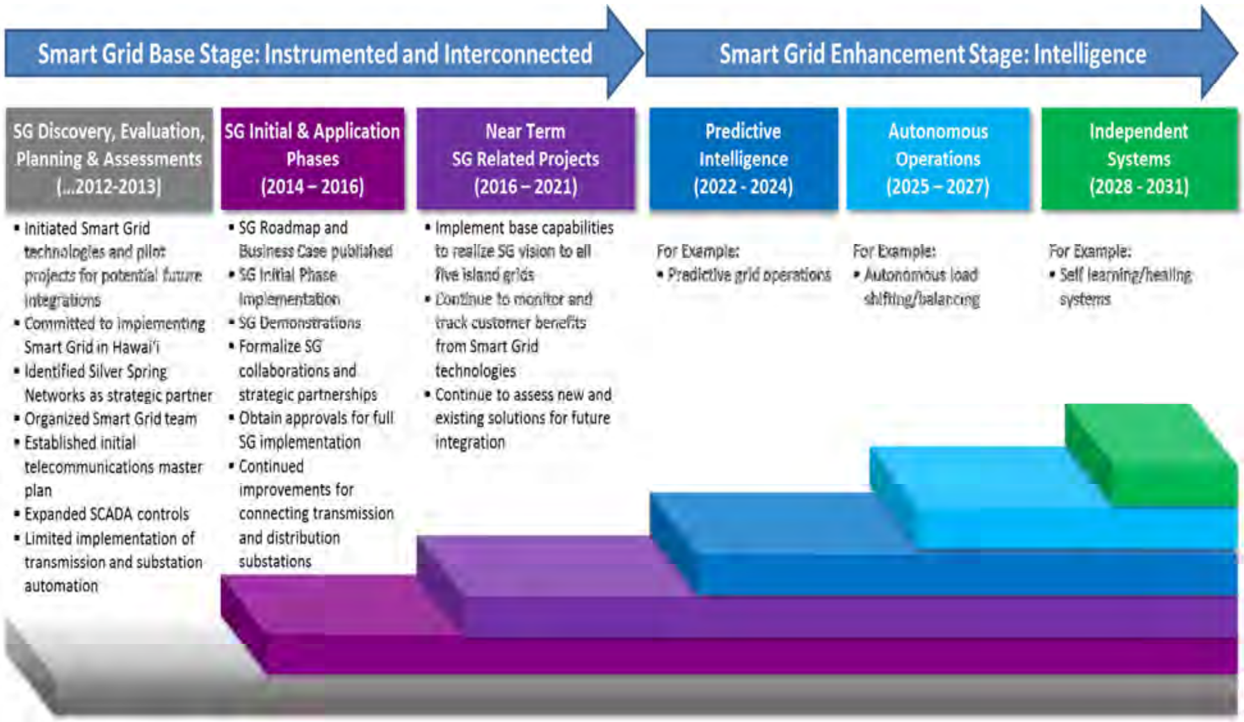
As explained above, the Companies' Smart Grid deployment strategy uses a phased approach, with the core infrastructure and basic functionality put in place first, followed by progressive incorporation of additional solutions over time due to the reality that some solutions do not yet commercially exist. Accordingly, the Companies have mapped the delivery of our Smart Grid vision along two main time horizons: (1) the overall twenty-year long-term (2012-2031); and (2) the sub-set near-term Smart Grid Related Projects (2016-2021).

A. Overall 20-Year Long-Term Smart Grid View (2012-2031)

The twenty-year long-term view shows what we have done to-date and directionally indicates our long-range Smart Grid plans, subject to revision as our near-term plans adjust and/or are implemented. This view is used to guide the Smart Grid activities in a strategically focused direction. Although this direction will evolve over time, it is generally stable and aligned with long-term views of the industry and the expected State energy policies in Hawai‘i.

Figure 8 below depicts our long-term Smart Grid view as divided into two major sections: (1) a "Base Stage," in which the basic capabilities and foundational infrastructure are assessed, implemented, operated and monitored; and (2) an "Enhancement Stage," in which additional capabilities that have yet to be fully commercialized are layered on top of the base in order to complete the implementation of a modern power grid that realizes our Smart Grid vision.

Figure 8 – Our Smart Grid Overall 20-Year Long Term View



Our Smart Grid journey formally began in 2008, with the submission of an initial AMI only application. At that time, we determined that we could not afford to be an early adopter and therefore, were delayed until the 2012-2013 timeframe to develop our initial roadmap and strategic partnership with SSNI, and subsequently carried out the Initial Phase and preparation for the SGF Project application. Outside of the Initial Phase demonstration, our power grid today does have some base capabilities for limited connectivity, information creation and operational control. These capabilities are mostly traditional and provide basic information for traditional dispatchable resources.

Our Smart Grid plan has been to build upon this traditional basis and improves on it by introducing and expanding smart capabilities beyond transmission and distribution substations, into service locations (e.g., smart meters). From 2012 through 2015, we improved our understanding and knowledge about our Smart Grid and are further building upon the Smart Grid learnings and experiences collected in the early discovery, evaluation, planning and assessment phase. We have also completed our Initial Phase and are now well into the Application phase. The year 2016 marks the start of the next phase within the Base Stage, and with support from our customers, policy makers and stakeholders, we are now looking to implement the Near-Term Smart Grid Related Projects phase in which the foundation will be established.

In achieving the Base Stage, our Smart Grid will be instrumented and interconnected from the transmission through distribution networks and to the service location levels. With the base in place, we can then focus on enhancing power grid capabilities and leveraging the developing technology advancements in storage and DER management. The collection and analysis of "big data" now enabled, collected and analyzed will allow for greater predictive intelligence, autonomous operations and independent systems in the future.[23]

The Enhancement Stage ushers in a future that is still being formulated. IEEE paints the picture of a progression of technologies that will allow for fully autonomous systems that will not only support real-time interactions but also provide predictive capabilities.[24] We acknowledge that there is still a lot of work to be done to fully flush out this portion of our Smart Grid roadmap. Nonetheless, it is provided to guide our overall broad Smart Grid strategic level decision making.

B. Near-Term Smart Grid Related Projects View (2016-2021)

The near term view of six years (2016 through 2021) provides a working construct of interdependent Smart Grid-related projects that connects the dots between the Companies' various plans, strategies and dockets currently before the Commission. This view is organized utilizing the key strategic themes, the associated solutions, their planned corresponding Commission applications, and target years of implementation. These are reflected on the near-term roadmap based on interconnected planning assumptions that not only provide the basis for scope and timing, but also for its inter-dependencies. For example, it is not possible to offer RTP without the Meter Data Management System ("MDMS") solution that is connected to an installed base of smart meters. Details of the various projects are not presented in this roadmap, but rather have or will be provided in the associated applications for Commission approval of the respective projects, as listed below:

Smart Grid Foundation Project contains requests for approval of the base Smart Grid technologies needed to implement foundational capabilities that include the AMI solution (i.e., smart meters, the multi-directional communications network, the CFS and the MDMS), enhance DR capabilities to replace end-of-life one-way water heater direct load control ("DLC") to smart devices, implement the Volt-VAR Optimization solution that will enable conservation voltage reduction ("CVR"), back office supporting capabilities for integrating, warehousing and analyzing data, and the propose a non-standard meter tariff.

DR Aggregator Contracts represents the request for approval of firm provider contract(s) resulting from negotiations expected to take place in the first half of 2016. These negotiations will focus on the shortlisted vendors selected pursuant to request for proposals #061715-02, "Provision of Grid Services Utilizing Demand-Side Resources," issued in May, 2015.

DR Program Portfolio (Docket No. 2015-0412) contains the request for approval of Demand Response Program Portfolio tariff structure, reporting schedule and cost recovery of program costs through the Demand-Side Management (DSM) Surcharge. The December 2015 filing is considered preliminary at this stage due to the need to sync up the planning assumptions

[23] "Big Data" is a term coined in 2001 by MetaGroup (now known as Gartner) to depict data sets so large or complex that traditional data processing is no longer adequate to capture, store, search, analyze, share and visualize.
[24] The IEEE Grid Vision 2050 Roadmap describes the IEEE Power and Energy Society's vision of the power system infrastructure into the year 2050 and provides for discussion a roadmap of the associated power and energy technologies.

with the updates of the Power Supply Integrated Plans ("PSIPs") on April 1, 2016. Therefore, this docket update will be scheduled for after mid-2016 to include final program riders, sample contracts and implementation plan including demonstration projects.

Demand Response Management System ("DRMS") Project (Docket No. 2015-0411) contains the request for approval to defer certain computer software development costs for the DRMS, to accumulate an allowance for funds used for construction during the deferral period, to amortize the deferred costs, and to recover deferred, amortized costs through the Renewable Energy Infrastructure Program Surcharge.

EV Time-of-Use rate schedules (Transmittal No. 15-08 and Docket No. 2015-0342) contained requests to approve modifications to existing EV time-of-use ("TOU") rates and schedules, and to approve new proposed rates and schedules. The Commission has issued Decision and Order No. 33165 and Decision and Order No. 33279 in which extension and transition of EV TOU rates and schedules were approved but conditioned on adjudicating these EV rates and schedules together with the overall TOU rate design in DER Phase 2 (discussed below).

DER Time-of-Use rate schedules (pursuant to Order No. 33258) contained the request for approval of DER TOU (includes EV) rates and schedules that are complementary to the DR Program Portfolio. These are included in the DR Program Portfolio as a rate within the Capacity Service Tariff. The currently proposed TOU design at the high level is for three fixed time periods, established based on marginal generation costs, and will be recomputed annually. This is subject to change pending the on-going discussions and collaboration with stakeholders.

Real-Time Pricing Tariff will contain the request for approval of the proposed RTP rates and associated schedules that leverage the use of the granular data that the AMI solution provides. This is one of the future DR programs as outlined in the recent DR Program Portfolio as discussed above.

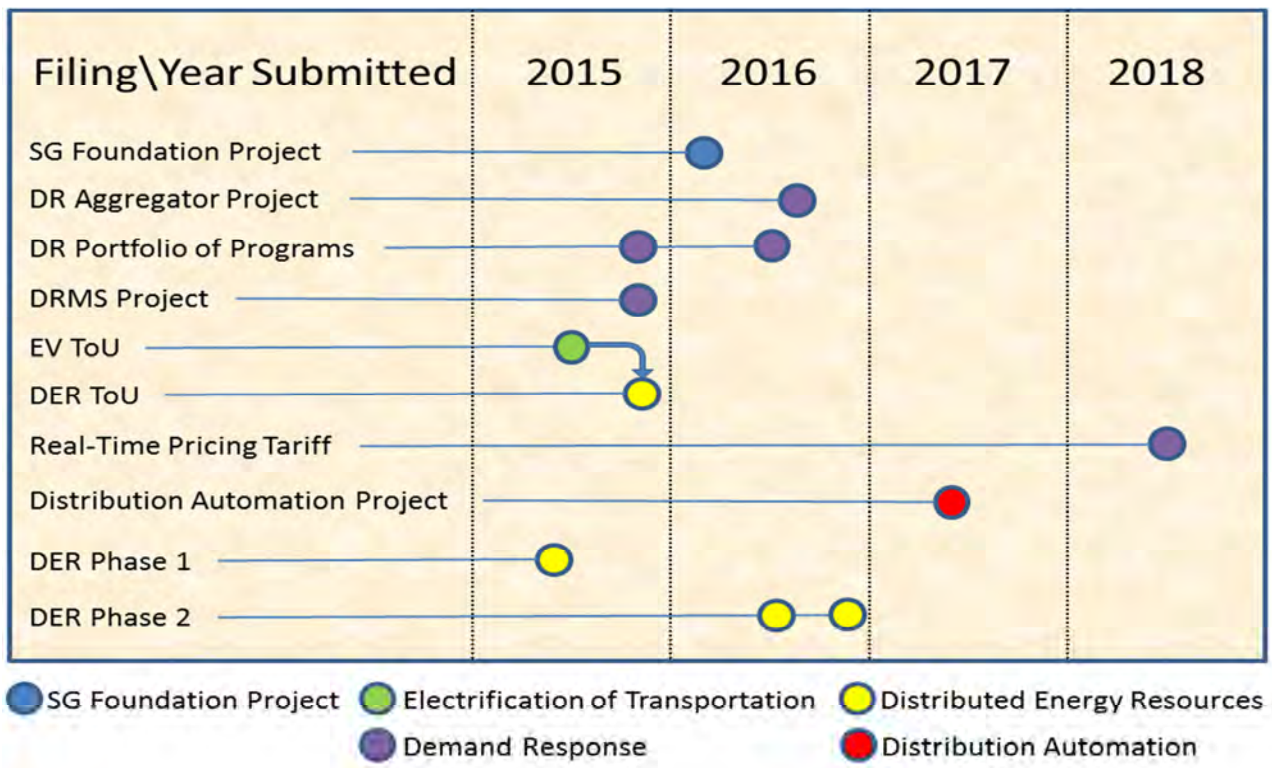
Distribution Automation Project will contain the request for approval of distribution smart field devices, communications, and the associated Advanced Distribution Management System ("ADMS") that will be used to enhance our outage management capabilities and provide incremental Smart Grid management functions that will increase power grid stability, reliability and resiliency.

DER Phase 1 (Docket No. 2014-0192) responded to the Commission's request to institute a proceeding to investigate DER. Based on that investigation, Decision and Order No. 33258 approved revised interconnection standards to streamline and improve the Companies' interconnection process, closed the Companies' net energy metering (NEM) program to new participants, and approved new options for customers to interconnect DER to the Companies' power grids (self-supply and grid-supply options).

DER Phase 2 is expected to address the following issues: (1) Hosting Capacity Analysis (circuit-level and system-level); (2) Opportunities to enhance the value of DER to the power grid (focused on integration and aggregation of various forms of DER); (3) The Companies' Integrated Interconnection Queue and further revisions to applicable interconnection standards to enable advanced DER capabilities and improve the interconnection process; (4) Establishment of communications protocols between utilities and DER; (5) Activation timeline and implementation process for advanced inverter functions; and (6) DER rate design and program structures. The current target is to complete DER Phase 2 processing by the end of 2016.

The anticipated timing for the various Smart Grid-related project applications is shown in Figure 9, below. Figure 9 also provides the base color coding legend for the subsequent Figures 10 through 14, which show the solutions contained within each docket by year grouped by strategic theme.

Figure 9 – Near-Term Smart Grid Related PUC Filings (subject to change)



The following sections outline how each of the filings and the associated solutions support the Smart Grid strategic themes by year. Each section has a corresponding figure that depicts the overall solutions within each strategic theme. Each bar within the respective figures represents the implementation of a particular solution. Each solution within its bar can have multiple progressive releases before final completion. In many cases, benefits are realized before the final completion of each solution.

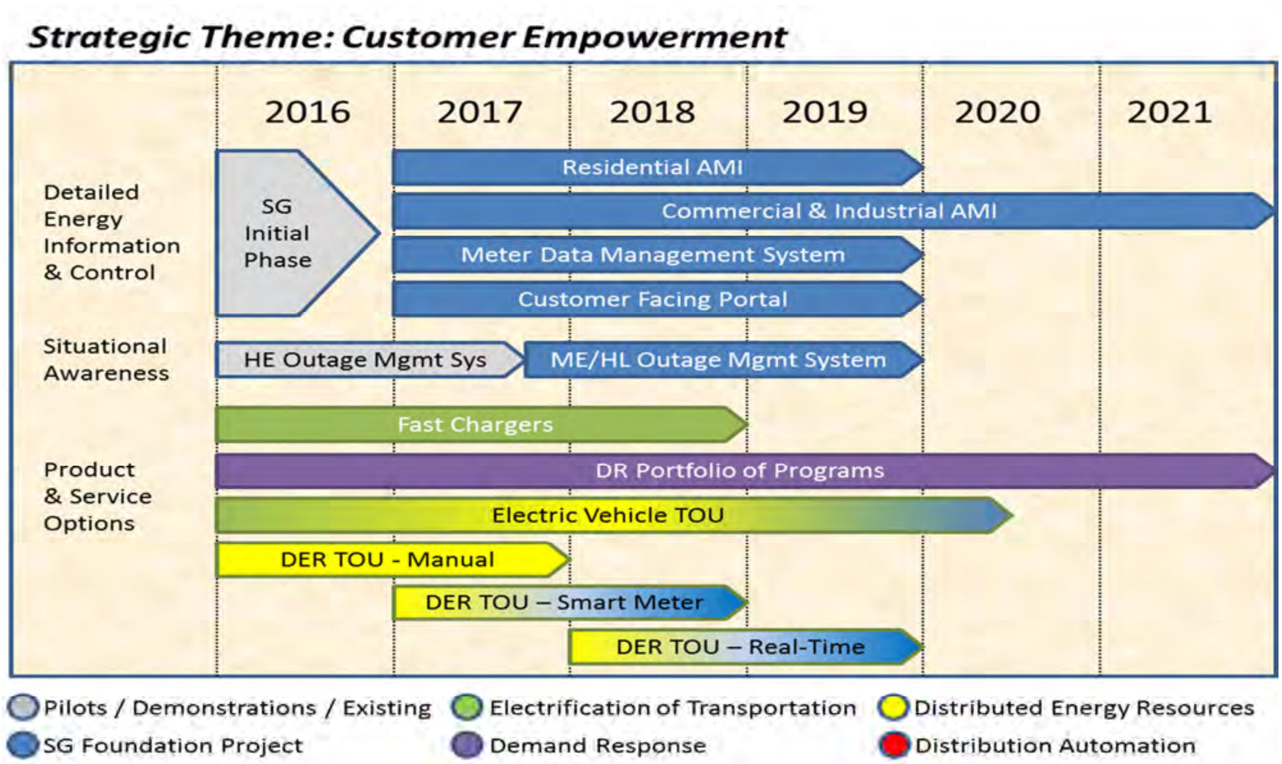
1. Customer Empowerment

Figure 10 below depicts the primary functions encapsulated under the Smart Grid customer empowerment strategic theme. It is in this timeframe that customers will gain access to their energy usage at a more granular level via their online or mobile one-stop customer experience portal. Customers will have access to new customer options and be able to compare products and services (e.g., new DR programs and options for further integration of EV options), in a unified customer experience. During power disturbances, customers will have greater visibility and situational awareness of outage occurrences and estimated restoration times. Additionally, traditional fixed-period TOU capabilities will be enhanced to more RTP programs once AMI is deployed.

There are three stages of TOU capabilities: (1) Manual TOU – which requires truck rolls to replace the existing meter with a TOU enabled meter, and to read the meter manually; (2) Smart Meter-enabled TOU – which utilizes the installed smart meter and communications network to remotely collect the TOU fix period energy use data; and (3) RTP – which utilizes the smart meter, smart communications network, and in addition, leverages the MDMS to dynamically and remotely configure, calculate and verify compliance to a RTP program.

While the manual TOU capability is available to customers today, enrollment in the manual TOU program is strictly based upon assumptions that a TOU customer's energy use behaviors (e.g., energy use during specific times of the day) are better suited for TOU rates. However, with Smart Grid, customers will be able to use their actual energy usage data to more accurately select the appropriate rate plan that fits their lifestyle and makes the most economic sense. The Smart Meter-enabled TOU capabilities will also increase operational efficiencies through the ability to switch a customer on or off of the TOU rate plan remotely, eliminating the need to send a person out to manually swap out the meter and switch services. Such remote capabilities will provide a more sustainable solution than our option today through easier access for customers and enhanced efficiencies in service.

Figure 10 – Customer Empowerment Near-Term Roadmap

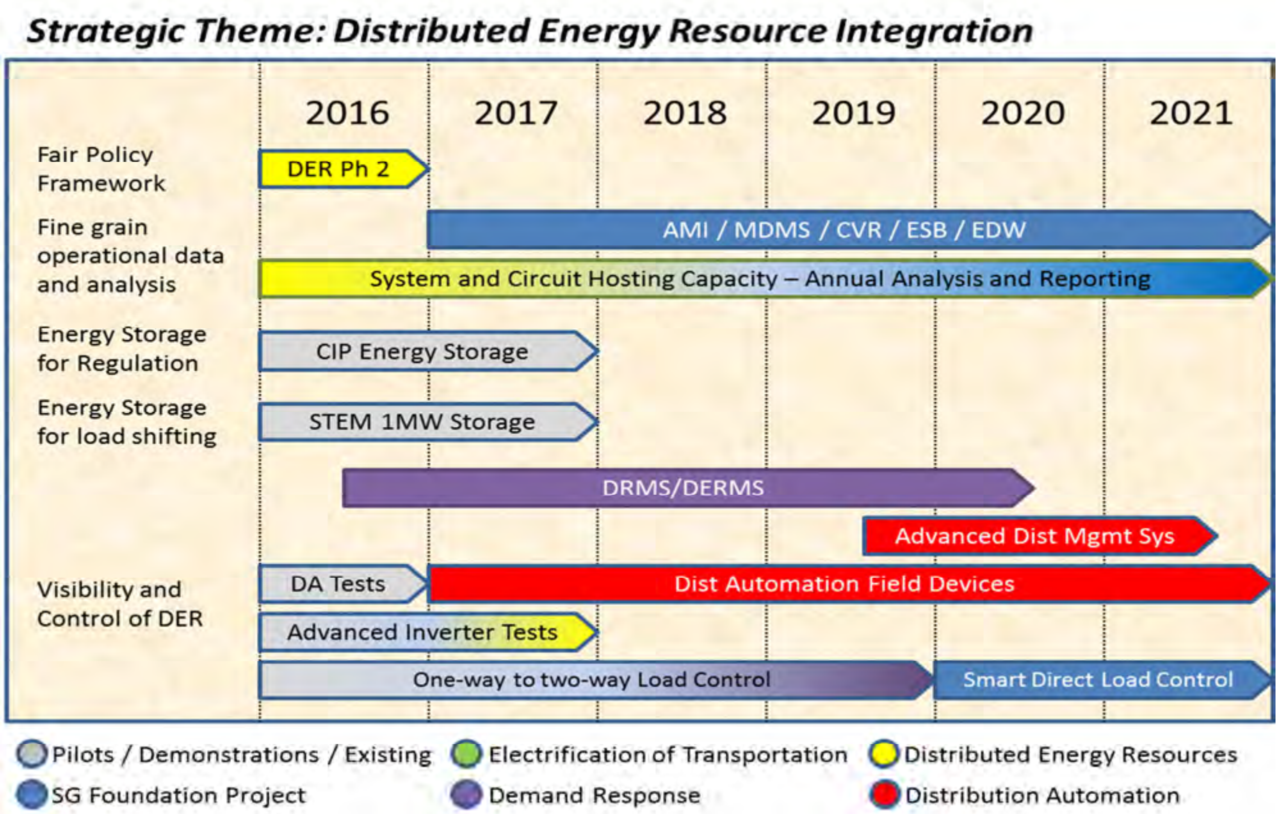


2. Distributed Energy Resources Integration

Figure 11 below depicts the primary functions encapsulated under the DER Integration strategic theme. Since a large portion of the capabilities in this space are still emerging, we have included a number of pilot/demonstration items (shown in gray) that are designed to test the proposed functions and capabilities. This includes visibility and controllability of smart devices located behind the meter and energy storage systems. There is also a planned lag in time for which an expected amount of DA smart field devices are installed before the "master control" ADMS is implemented.

This is possible because smart field devices have autonomous functions as well as limited central controllability. However, once the number of smart devices is at scale, the central system is then needed and its costs can be leveraged over a large population of smart devices. We have also included on the roadmap the assumption that the proposed DRMS is in fact a DER management system that will become fully integrated into the overall system once all the various components evolve and mature over time.[25] This approach is more cost-effective as we will be able to grow with a single solution, versus needing to procure and maintain two separate solutions.

Figure 11 – Distributed Energy Resource Integration Near-Term Roadmap



[25] See Exhibit C to the Companies' DRMS Project application in Docket No. 2015-0411 for further details on the selected Siemen's solution, which is in essence a DER management system.

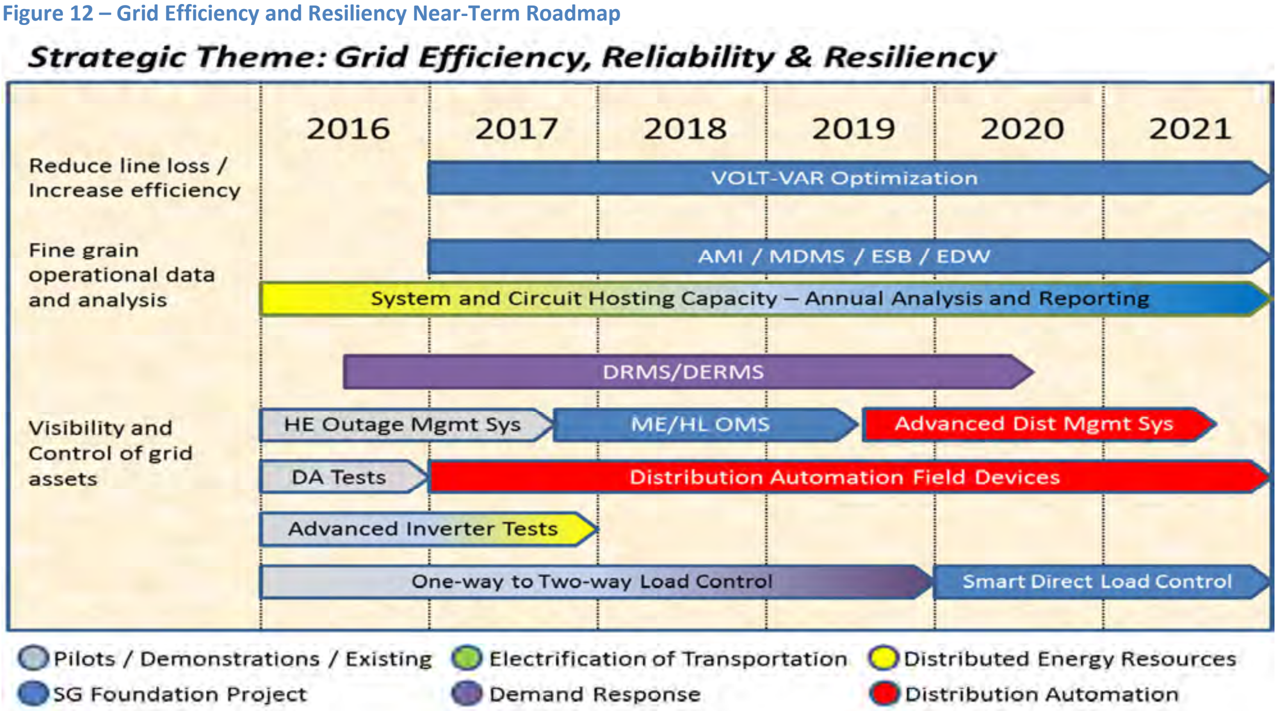
3. Grid Efficiency, Reliability and Resiliency

Figure 12 below depicts the primary functions encapsulated under the Smart Grid efficiency, reliability and resiliency strategic theme. In this case, Volt/VAR Optimization (VVO) relies on the AMI smart meter and communications infrastructure in order to deliver CVR capabilities. Additionally, with the implementation of AMI, incremental operational information such as voltage and temperature from the service location level will be collected into the Enterprise Data Warehouse ("EDW") via the Enterprise Service Bus ("ESB") and will enhance our ability to effectively and efficiently share and analyze data in real-time or near-real-time. This will further enhance our modelling and visualization capabilities and will be especially helpful in cross-functional analytics such as system and circuit hosting analyses.

This roadmap also represents the functional maturation required to move from an OMS to a fully matured ADMS system that will centrally manage in aggregate all distribution resources. It is important to expand automated outage capabilities first in order to implement the foundational reliability capabilities associated with reducing outage durations. This is why the ADMS system implementation follows after the implementations of the MDMS, DRMS/ DERMS and OMS are completed – and once enough distribution smart field devices have been implemented.

There are items on this roadmap that are still in test phases (e.g., advanced inverters, in-line power regulators). Once proven, these items will ultimately feed into the formalization of solutions that will then be implemented. Existing capabilities will also evolve into the more mature Smart Grid two-way information and controls (e.g., DLC). An item that is currently not on the roadmap but will be added once evaluated, is the use of energy storage at the distribution level in response to providing greater power grid stability.

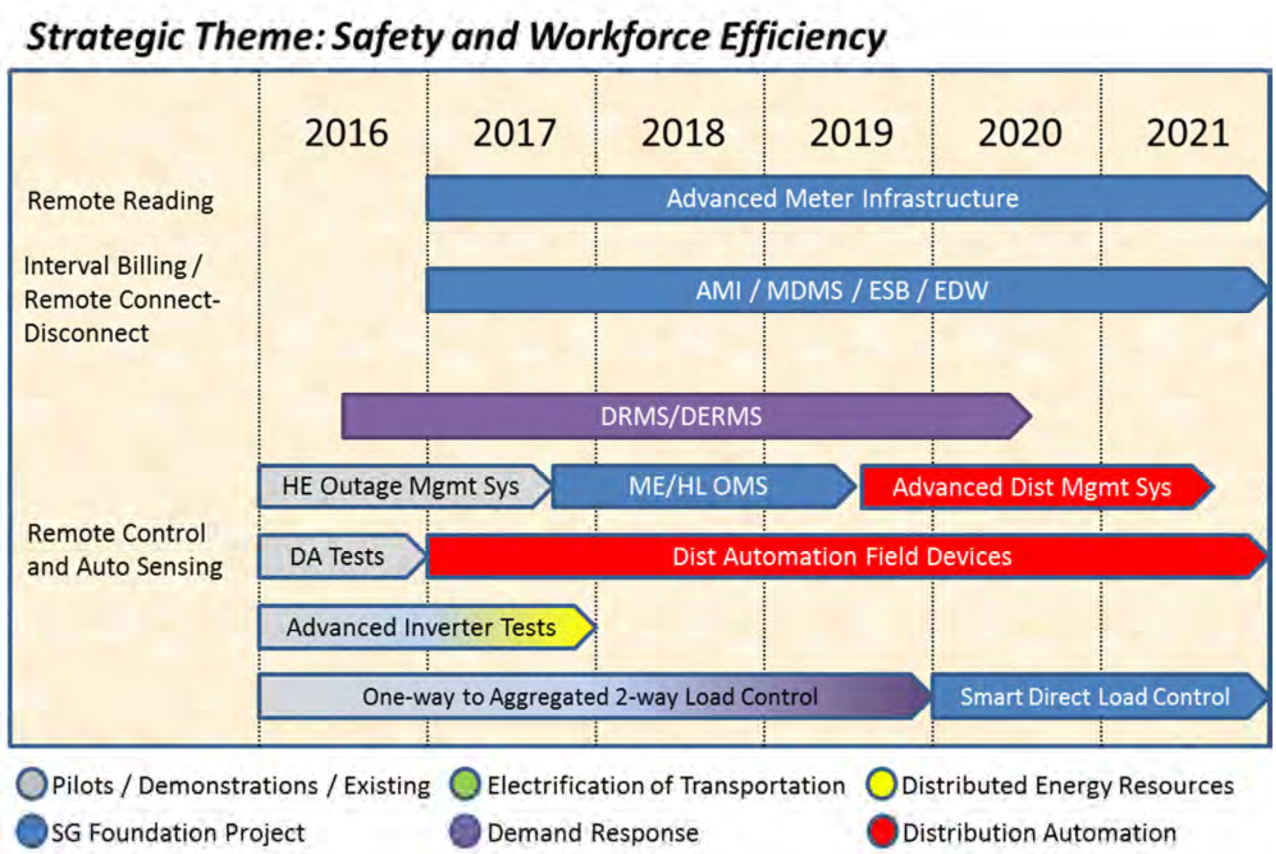
Figure 12 – Grid Efficiency and Resiliency Near-Term Roadmap



4. Safety and Workforce Efficiency

Figure 13 below depicts the primary functions encapsulated under the Smart Grid safety and workforce efficiency strategic theme. This component of the roadmap shows when the expected capabilities that improve safety and workforce efficiency will be delivered by the associated solutions. Specifically, we expect that with AMI and the MDMS, ESB and EDW, we will attain the ability to remotely read all meters and therefore, be able to reduce the number of existing meter reading positions (although some may still be retained due to the need to manually read non-AMI meters for customers who chose not to have a smart meter installed or are located in geographic areas that do not support electronic communications). Each of the capabilities represented under this strategic theme allows us to increase efficiency and productivity, while maintaining the safety of our workforce. The increase in smart devices that are capable of autonomous actions will reduce the time to action (e.g., no need to roll a truck to change a switch setting) and central monitoring capabilities will further enhance our system operations capabilities to process complex amounts of data quickly in order to mitigate grid issues. As we begin deploying these new technologies, we will implement a training program for our affected workforce so that the value and benefit of the technologies and more efficient work processes can be fully realized.

Figure 13 – Safety and Workforce Efficiency Near-Term Roadmap

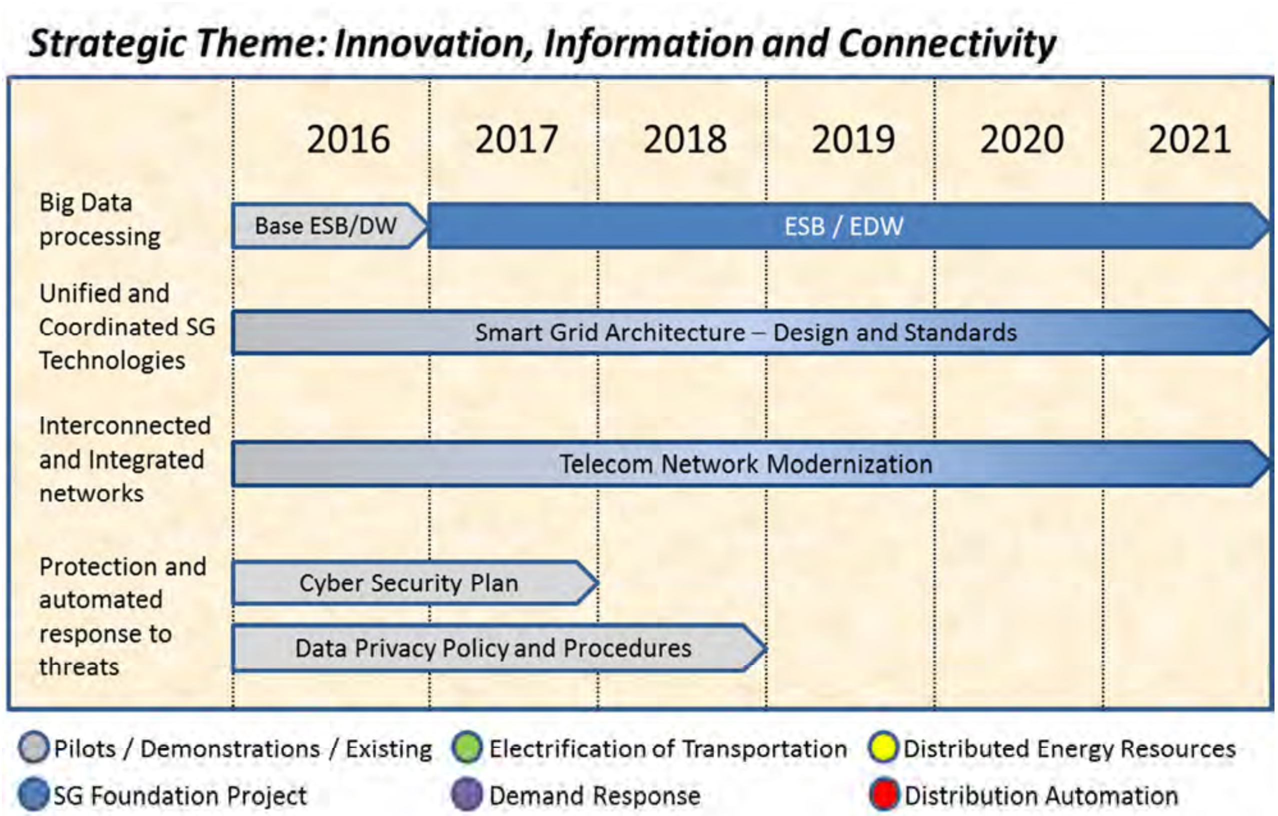


5. Innovation, Information and Connectivity

Figure 14 below depicts the primary functions encapsulated under the Smart Grid innovation, information and connectivity strategic theme. This portion of the roadmap shows capabilities that are key technical components as well as security and privacy policies and procedures that need to evolve over time in order to keep pace with the rapidly evolving nature of Smart Grid technologies. Since many of the technical solutions are still evolving (e.g., integration of advanced smart inverters), our technical capabilities need to be grounded in flexible frameworks that supports continuing innovation and change over time.

Many of the capabilities listed here (except for big data processing) already exist and only need to be improved and enhanced as we introduce newer technologies that change the way we serve our customers and manage the power grid. Our base ESB and data warehousing capabilities today only process a limited amount of data and support just a few applications for transaction interchange. With the implementation of Smart Grid, there are many incremental systems to be added to the overall environment and the data volume will exponentially increase. Once the major updates to the associated plans are in place, they will be revisited annually or as changes in assumptions occur. We do not expect these plans to remain static, as new capabilities are discovered and the plans will be updated in order to remain current and well maintained.

Figure 14 – Information and Connectivity Near-Term Roadmap



VII. CONCLUSION

By enabling more informed and timely energy decisions, Smart Grid is bringing enormous changes for the electric industry in general and the State of Hawai'i in particular. Our Smart Grid vision is to provide an intelligent and automated electric system that utilizes multi-directional communications and computing technology advancements to better meet customers' expectations, State energy policy objectives, communities' energy demands, and the Companies' overarching responsibility to provide safe, reliable and secure electric service. Our strategy for making this vision a reality is focused on delivering our Smart Grid strategic themes: (A) customer empowerment; (B) DER integration; (C) power grid efficiency and resiliency; (D) safety and workforce efficiency; and (E) innovation, information and connectivity.

Building a Smart Grid in Hawai'i will not be accomplished in a single project effort, but will evolve over time, growing and layering capabilities and functionality that increasingly deliver incremental value to customers. When taken in their entirety, the overall bundle of benefits and capabilities enabled by our Smart Grid initiatives supports a positive value proposition and business case, with a benefit-to-cost ratio of approximately 1.2, which will lower costs for the Companies and their customers in the long run. We look forward to working with the Commission, Consumer Advocate and other stakeholders on their ongoing, near- and longer-term initiatives to make Hawai'i's Smart Grid a leading model within the industry.

APPENDIX A – Definitions and Abbreviations

To aid understanding, this appendix contains definitions for many of the terms and acronyms used throughout this document.

Advanced Analytics and Forecasting: Advanced Analytics and Forecasting allows for a tighter balance between energy supply and demand, thus saving energy. It provides more detailed, immediate information about how energy is being used within a customer location, which helps develop more dynamic demand forecasts.

Advanced Distribution Management System (ADMS): ADMS is a software platform that supports a full suite of distribution management by incorporating data, status and control capabilities delivered by OMS, DMS and SCADA systems. An ADMS can deliver optimization to system operators by integrating its own asset pool and those managed by an EMS upstream and the DERMS and/or MDMS downstream. The ADMS typically manages distribution system assets such as feeders, transformers, cap banks, switches, relays, DA, regulators, etc. It can also be coordinated with and leverage information and control of distributed assets on the customer side of the meter. ADMS functions include automated outage restoration, fault location, isolation and restoration; volt/volt-ampere reactive optimization; conservation through voltage reduction; and support for energy storage, micro-grids and electric vehicles that are directly tied into the distribution network.

Advanced Metering Infrastructure (AMI): The hardware and software, together with the telecommunications services, that enables: (1) automated meter reading, (2) the collection of meteorological data; and (2) the control of meters. AMI integrates advanced metering data and controls from the meter all the way through to back office systems.

Back Office: The internal business operations and systems of a company that are not visible to the general public.

Conservation Voltage Reduction (CVR): A technique under VVO for improving the efficiency of the power grid by optimizing voltage on the feeder lines that run from substations to homes and businesses.

Critical Peak Pricing (CPP): A hybrid of time-of-use and real-time pricing. Utilities charge fixed time-of-use rates for preset periods but might charge higher rates during periods with the highest demand of "peak" periods. Customers are notified in advance of the price change, allowing them time to reduce energy usage.

Customer Payment Options (CPO): Combination of a broad array of payment technologies offered to customers; inclusive of credit and debit transactions utilizing the automated clearing house, and pre-payment and/or gift card solutions.

Customer Facing Solutions (CFS): Interactive web/mobile application platform that is viewable to the customer directly, and includes but is not limited to an energy portal, profile and preference management, billing options, and other web/mobile customer interactions. The CFS utilizes the MDMS and ADMS systems in order to convey energy usage, estimated bill, outage information, etc. to customers in near real-time.

Customer Information System (CIS): A suite of software programs that stores a plethora of information about utility customers. The CIS system also stores meter and customer generation data.

Distributed Energy Resources (DER): Distributed energy resources include distributed generation, energy efficiency, demand response, electric vehicles, and distributed energy storage.[1]

Distributed Energy Resource Management System (DERMS): A software platform that enables status, command and control of a wide array of customer-sited, behind-the-meter, distributed energy resources and the programs that allow for the management of these resources (including Demand Response programs). This system employs a "system of systems" approach to facilitate the coordination across multiple head-end systems and direct end use communications and delivers grid services to system operators. To do so, the DERMS maintains current status on and optimizes the distributed asset pool, including those managed directly through DR programs, to allow an energy company to deliver a full spectrum of ancillary services through these resources. The solution also accurately measures and verifies the delivery of these services.

Demand Response (DR): Programs that reward customers for smart energy usage and save money during periods of peak demand through the voluntary curtailment of their consumption when demand is high or during periods when their continued use might jeopardize the stability of the electrical system. Fully automated DR can be initiated at a home or building by an external signal, which initiates pre-programmed shedding strategies. Facility staff at each site will pre-program the control systems to receive the signals. The energy company can provide payments as an incentive to participate in DR programs.

Demand Response Management System (DRMS): A solution that optimizes DR programs offered by an energy company, enabling the DR programs to be viewed as a single asset. This solution allows an energy company the ability to optimize load shedding customers while managing peak load by precisely estimating the potential available load shed in time. The solution also accurately measures and verifies load shed events.

[1] Hawaii Public Utilities Commission, at 1 Docket No. 2014-0192, *Decision and Order* No. 33258.

Direct Load Control (DLC): A DR program that enables a system operator to interrupt a customer's load during the period of peak load. DLC is enabled by a utility-installed device that remotely controls equipment such as a central air conditioner or a water heater. During periods of heavy use of energy, a system operator can send a signal through this device to turn off or cycle off and on the appliance for a set period of time.

Distribution Automation (DA): A system comprised of control applications, communication networks and field devices, where the field devices are installed anywhere on the distribution system from inside a substation to the high side of the customer transformer, enabling remote control, monitoring, and automation to support the planning, engineering, construction, operation, and maintenance of the distribution system.

Distributed Generation: A system that involves small amounts of generation or pieces of generation equipment applied to a energy company's distribution system for the purpose of meeting local peak loads, sometimes displacing the need to build additional infrastructure. Distributed generation can take many forms, but predominately it is in the form of wind or private photovoltaic systems.

Electric Power Research Institute (EPRI): An industry association that conducts research, development, and demonstration related to electric generation, delivery, and use for the public's benefit. This independent, nonprofit organization brings together scientists and engineers as well as experts from academia and the industry to help address challenges in electricity.

Enterprise Data Warehouse (EDW): Central repository of integrated data from one or more disparate sources used in support of analysis, reporting, simulation, forecasting and machine learning.

Energy Management System (EMS): A system of computer-aided tools used by system operators of power grids to monitor, control, and optimize the system level performance of the generation and transmission systems.

Enterprise Service Bus (ESB): Software platform that supports and facilitates the use of service-oriented architecture to efficiently design and implement data communications, sharing and inter-operability between disparate software applications.

Fault Circuit Indicator (FCI): A device placed in the field that provides either a local or remote indication of a fault (or problem) on an electrical circuit.

Geographic Information System (GIS): A system designed to capture, integrate, store, edit, analyze, manage and display all types of spatial or geographical information.

Home Area Network (HAN): A data communications system contained within a home or small to medium business that communicates with other HAN devices.

IPv6 (Internet Protocol Version 6): The latest revision of the IP communications component that identifies and locates computers and devices on networks and routes traffic across the Internet. IPv6 was developed by the Internet Engineering Task Force (IETF) to deal with the long-anticipated problem of IPv4 address exhaustion.

Load Shedding: The process of deliberately removing preselected customer demand from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

Local Area Network (LAN): Computers and other devices that share a common link within a geographic area.

Mesh Communications Network: A LAN of continuously connected meter end nodes, access points and relays that connect to and communicate with adjacent nodes. In a mesh network, devices collaborate to propagate the data in the network.

Meter Data Management System (MDMS): A system that performs the management and maintenance of smart meters, inclusive of its long-term data storage and management for the large quantity of data delivered by smart metering systems. The MDMS imports the meter data, then validates and processes it so it can be used for billing and analysis. It also manages and controls the meter configurations and statuses, and performs connects and disconnects through the smart meter head-end. It will also aggregate meter outage information for upstream systems like an OMS or ADMS to consume, while providing meter usage data to DRMS or DERMS for the verification of DR Program utilization.

Neighborhood Area Network (NAN): The Companies' last-mile, outdoor access network that connects smart meters and DA devices to each other and to an access point device. These NAN access points communicate to the Field Area Network (FAN) or to the Wide Area Network (WAN) gateways through a cellular or Ethernet connection.

Net Energy Metering (NEM): An agreement that allows private residential and commercial utility customers to effectively accrue solar generation credits by selling back excess energy. The NEW agreements enabled customers to interconnect their eligible, independently-owned and operated renewable energy generation system generating up to 100 kW to the Companies' power grid (according to Hawai'i State law, Hawai'i Revised Statutes (HRS) Sections 269-101–269-111). The executed agreement allows the NEM customer to connect their renewable generator to the power grid, allowing it to export surplus energy into the grid, and to receive credits at full retail value that can be used to offset energy purchases over a 12-month period. NEM was retired in October 2015, and replaced with two new programs, called Customer Self Supply and Customer Grid Supply.

Online Customer Energy Portal: An online solution where customers can monitor their usage and make more informed choices on how to lower their energy bills.

Open Analytics Platform: A unified solution designed to address the demands of users, especially large data-driven companies, on the inadequacy of relational database management systems in providing contextual analyzed data out of all the stored information.

Outage Management System (OMS): A computer-aided system that allows an energy company to receive customer calls or indications from the SCADA system to manage and restore electrical outages. An OMS is generally integrated with a work order management system, and utilizes the ADMS for functional interoperability.

Real-Time Pricing (RTP): A DR program that provides pricing signals to encourage customers to use energy during times of the day where energy has a lower cost.

SCADA (Supervisory Control and Data Acquisition): This computer-controlled system remotely monitors and manages electrical equipment (such as substation electric circuit breakers, substation transformers, and electrical switches).

Time-of-Use (TOU): An electric utility billing rate where the rate varies by period of time during the day when the energy is actually consumed. The rate is usually based on expected average cost – lower cost during periods of low demand and higher during periods of peak demand.

Vol-Var Optimization (VVO): Techniques in which voltage on the power grid can be optimized in order to conserve energy (i.e. CVR) and/or to shed load via a DR capability.

Attachment 1

Smart Grid Foundation Project

Exhibit A

Third-Party Support Letters

Kanu Hawaii

March 9, 2016

Letter of Support

Based on five years of on-the-ground field work across the state working with disadvantaged and hard to reach electricity consumers, **Kanu Hawaii strongly supports Hawaiian Electric's smart meter upgrade efforts**. This includes installing thousands of smart energy devices, working directly with hundreds of ohana, and distributing thousands of energy-saving devices. Our specific reasons for support are because the smart meters will:

1. Enable all electricity customers to potentially participate in demand response programs versus only homeowners with batteries for instance as smart meters can enable water heaters and air conditioning systems to provide interactive grid services. About 40% of our ohana have electric resistance water heaters for instance that could participate in load shifting, providing direct benefits to customers and relatively cheap load shifting to the grid.

2. Potentially reduce energy bills through value added services based on access to energy usage information. There are already tools that can disaggregate energy usage to "guess-timate" the costs to run specific appliances. With this information, people can better manage their usage. Appliances are expected to become even easier to use and be accessible to consumers with smartphones.

3. Remotely monitor energy usage which could be very useful in extended family care. We take care of our kupuna. In the future, with access to energy usage information in near real time, we can potentially check if stoves were left on or if there is no usage, potentially identify a medical situation. This is an example of a low cost value added solution that could be enabled by smart meter data.

4. Provide gamification options that could challenge users to use less energy and track and send notification of progress. This becomes an especially important management tool as we move towards time of use (TOU) billing. With TOU our most vulnerable residents could be least able to shift loads and so tools to help manage their usage will become important to maintain equity.

We firmly believe smart meters can help bring a bit more equity and solutions to electricity customers that have been chronically underserved. Mahalo for your consideration.

Sincerely,

Nicole Brodie, Executive Director

Olin Lagon, CEO of Shifted Energy, a Kanu subsidiary

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS
LOCAL UNION 1260
ORGANIZING THE FUTURE

IBEW
LOCAL 1260
ORGANIZING THE FUTURE

BRIAN F. AHAKUELO
BUSINESS MANAGER/
FINANCIAL SECRETARY

March 28, 2016

The Honorable Randall Y. Iwase, Chair
Public Utilities Commission
465 South King Street, #103
Honolulu, Hawaii 96813

Dear Mr. Iwase:

For too long, working families in Hawaii have had to deal with the impact of volatile oil prices on our state's economy. So it's vitally important that we work toward our state's goal of a 100 percent renewable portfolio standard, which is the most aggressive in the country.

It is no longer a matter of 'if', but 'when' we make our conversion to renewable energy. IBEW Local 1260 is committed to embracing the changes that are now necessary, both in Hawaii and across the country, to adapt to this new reality. This will help drive economic growth in Hawaii and provide new opportunities in terms of jobs for current and future union members.

An essential step in this transformation is the development of a smart grid. We need to implement new technologies and modernize our electric systems to adapt to this new environment. Our electric system must evolve to incorporate more renewable energy, make service more reliable, and empower customers to save energy and money.

Renewable resources such as solar and wind power are just part of our state's energy future. A smart grid will provide the foundation for other programs, such as taking advantage of advances in energy storage, greater adoption of electric vehicles, and expanded programs that will help customers take greater control of their energy use.

Integrating cutting edge smart technology into the existing electric grid will require a highly trained, skilled, efficient workforce. The smart grid will bring the electric grid into the information age, and the training and opportunities for the workers who will operate and maintain these systems must also evolve. By implementing this technology, we will support the growth of our state's economy by developing the workforce for the future.

Our state's transition to renewable energy is one of the most significant things we can do to secure the futures of our working families. At IBEW Local 1260, we believe we must make every effort to support this change. Developing a smart grid is a key, fundamental step that we must take to continue our progress.

Sincerely,

Brian F. Ahakuelo

Brian F. Ahakuelo
Business Manager/Financial Secretary

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March 30, 2016

leidos

Mr. Richard Houck
Vice President, Enterprise Project Management
Hawaiian Electric Company
PO Box 2750
Honolulu, HI 96840

Subject: Smart Grid Letter of Support

Since beginning the Hawaii Energy programs in 2009, Leidos, as the State's Public Benefits Fee Administrator (PBFA) has had a good and continual working relationship with the Hawaiian Electric Companies (HECO). This began with the transfer of the efficiency program materials and customer data from HECO to the PBFA, and it has continued over the years with mutual support for customer outreach and education through joint public events and efficiency initiatives. Recently, Leidos has worked with the HECO companies to define a collaboration framework to allow greater coordination of overall efficiency efforts while minimizing potential duplication of ratepayer monies being spent.

Hawaiian Electric has continually engaged the Leidos team as they design their smart grid initiatives. We believe that smart grid initiatives are an essential component to address Hawaii's energy challenges, and we anticipate that engagement and collaboration will continue as all stakeholders move forward to Hawaii's Smart Grid of the future. Leidos fully supports HECO's efforts to integrate smart grid resources together with energy efficiency.

Should you have any questions or require any additional information, please do not hesitate to contact me at 703.725.7758 or via email at james.m.gariepy@leidos.com.

Sincerely,

Leidos Engineering, LLC

James M. Gariepy

James M. Gariepy
Vice President, Energy Efficiency Services

Exhibit B

Smart Grid Foundation Project

Hawaiian Electric Companies' Business Case

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HAWAIIAN ELECTRIC COMPANIES' BUSINESS CASE

Throughout its progressive implementation, Smart Grid will play an increasingly pivotal role in Hawai'i's energy future. This business case is being provided in support of the Hawaiian Electric Companies' accompanying Smart Grid Foundation Project ("SGF Project") application ("Application").[1] The sections that follow discuss the various components of the SGF Project along with its costs, benefits and economic justification that are proposed as a best fit/least cost option for building the Smart Grid in Hawai'i in support of the 100% renewable energy goal for the State of Hawai'i.

I. SGF PROJECT DESCRIPTION

The purpose of the SGF Project is to establish the initial Smart Grid capabilities that will serve as the platform to support not only the SGF Project, but also additional projects specific to expanding customer options, such as demand response ("DR"), time-of-use rates ("TOU") and real-time-pricing ("RTP"), which will be introduced to customers over the next several years through separate proposed applications. At a high level, the network created by the SGF Project will increase visibility and control of the grid, thereby improving reliability and enhancing customer choices through new products and services.

In consideration of the most beneficial Smart Grid components currently available on the market, the Companies have selected eight specific solutions that have been proven commercially viable in other utility Smart Grid implementations in the United States.[2] Although additional newer solutions exist that utilize the Smart Grid infrastructure, such as Distribution Automation ("DA") which utilizes an Advanced Distribution Management System ("ADMS"), the Companies will continue to monitor and test the viability of these additional solutions and plan to submit a separate application in the future for their implementation once the reliability business case has been vetted and the potential solutions reach market maturity.[3]

A. SGF PROJECT COMPONENTS

As summarized below, the SGF Project will consist of ten major components:

- Eight subprojects, including: (1) Advanced Metering Infrastructure ("AMI"); (2) Customer Facing Solutions ("CFS"); (3) Conservation Voltage Reduction ("CVR"); (4) Direct Load Control ("DLC"); (5) Enterprise Data Warehouse ("EDW"); (6) Enterprise Service Bus ("ESB"); (7) Meter Data Management System ("MDMS"); and (8) Outage Management System ("OMS");
- Customer engagement ("CE") activities to support the eight subprojects; and
- Project management office ("PMO") shared services in support of the eight subprojects and supporting CE activities.

---

[1] The "Hawaiian Electric Companies" or "Companies" are Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Maui Electric Company. Limited ("Maui Electric") and Hawai'i Electric Light Company, Inc. ("Hawai'i Electric Light").
[2] <u>See</u> Exhibit A, the Companies' Smart Grid Strategy and Roadmap ("Smart Grid Roadmap").
[3] For information on the near future filing of the DA Project, <u>see</u> Section VI.B of the Smart Grid Roadmap.

Breakdowns of the deployment schedules and accompanying costs for each component are provided in Section II.B below.

1. Advanced Metering Infrastructure

AMI provides two-way communications between utilities and smart meters. This communication enables utilities to obtain consumption reads and voltage statuses at individual customer locations more frequently than existing manual meter reading cycles. This capability is further enabled through the use of on-demand and automated meter reading functionalities provided by smart meters through the AMI network. At a high level, the installation of smart meters in connection with the AMI network will help customers to reduce their energy consumption, enable customers to participate in money saving rate options, provide increased visibility into the grid, shorten outages and make it easier to integrate increasing levels of customer-sited generation.

The deployment of AMI across the Companies' service territories within the SGF Project includes the installation of smart meters for all customers except for those who choose to not participate and/or unable to access the AMI network. The AMI network is a proven two-way common communications system network platform with a network management system that will monitor and manage communications with deployed smart meters, other smart devices located on the distribution network and cybersecurity measures.

2. Customer Facing Solutions

CFS encompasses any utility-hosted, forward-facing software application that creates a pathway in which customers can interact with the utility directly. For their Smart Grid Initial Phase demonstration project on O'ahu ("Initial Phase"), the Companies provided a basic and limited version of the Silver Spring Networks, Inc. ("SSNI") Customer IQ ("CIQ") online customer energy portal, which allowed customers to view their energy consumption at 15-minute interval time periods, but did not enable mobile capabilities, integration of the full customer experience or the ability to recommend new programs/rate plans to customers based on their usage, as will be enabled by the proposed CFS subproject.

The CFS subproject is optimized with responsive design for both desktop and mobile (includes laptops, tablets, and phones) computing devices that will utilize an enhanced and expanded online/mobile customer energy portal for customers and provide additional features to better serve customer needs. These include but are not limited to providing customers: (1) access to accurate energy usage data and trending analysis information so they can better plan for future energy needs; (2) information and alerts about their energy consumption to allow them to better manage their monthly energy costs; (3) the option to examine and compare available rates; (4) easier ways to enroll in available programs, such as DR and TOU; and (5) near-real-time information about service outages in their area.

3. Conservation Voltage Reduction

CVR uses voltage measurements from smart meters, which are obtained over an AMI network, to enable system operators to more accurately and dynamically control voltage fluctuations on distribution circuits. The voltage information collected from the smart meters results in utilities being better equipped to make adjustments at distribution transformers to lower voltages, which leads to a decrease in customer electricity consumption without requiring any changes to the customer's energy usage behavior. Ultimately, this decrease in customer consumption results in less fuel used to generate an adequate level of electricity to meet demand, which lowers the cost of fuel that is passed on to customers.

The Companies installed a small preliminary CVR solution on Oʻahu as part of their Initial Phase. Results from those studies validated the potential energy savings that can result from CVR. The CVR subproject includes an enhancement and expansion of this existing CVR capability at Hawaiian Electric, as well as an extension to applicable distribution circuits at Maui Electric and Hawaiʻi Electric Light.

4. <u>Direct Load Control</u>

DLC is used to reduce load during peak electricity use periods by allowing operators to balance the system frequency during the loss of a generator or a generation capacity shortfall situation. This is done by remotely shutting off a customer's water heater during these emergency periods, which thereby reduces load and allows for the operation of the grid in a safe manner – potentially leading to the avoidance of blackouts.

For the SGF Project, the Companies will be upgrading the existing DLC switches on Oʻahu so that they can use the AMI communications network to improve control of participating customers' water heater operations to stabilize the grid during peak demand.[4]

5. <u>Enterprise Data Warehouse</u>

An EDW is a system used for reporting and data analysis. EDWs are central repositories of integrated data from one or more disparate sources. They store current and historical data, which can then be used for creating analytical reports for use throughout the enterprise, such as allowing more customers to have DER sooner, as a result of smart meters providing increased visibility into the electric grid.

As part of the SGF Project, the Companies will be enhancing their existing EDW, which will serve as the source of record for enterprise-wide, cross business-function analysis. The EDW will incorporate and store data from existing enterprise systems in addition to the high volume of energy use and system operating data that will be acquired by the deployed technologies in the SGF Project, as well as other interconnected programs, such DR and any future projects that the Companies pursue to enhance grid functionalities.

6. <u>Enterprise Service Bus</u>

An ESB is a software architecture model used for designing and implementing communication between mutually interacting software applications in a service-oriented system.

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[4] By Decision and Order issued December 29, 2009 in Docket No. 2009-0097, the Commission approved a three-year extension of Hawaiian Electric's existing residential DLC water heater program ("EnergyScout"), but denied the program's expansion.

An ESB promotes agility and flexibility with regard to communication between various solutions.

The Companies plan to enhance their existing ESB as part of the SGF Project. This will facilitate the efficient and secure flow of customer usage data and grid operations information between the MDMS discussed below, the EDW and the Companies' other enterprise software applications.

7. Meter Data Management System

An MDMS is a key component of Smart Grid infrastructure that performs long-term data storage and management for the vast quantities of data delivered by AMI. This data consists primarily of usage data and events that are imported from the head-end servers that manage the AMI data collection. The MDMS will import the data, then validate, cleanse and process it before making it available for analysis and billing.

During the SGF Project, the Companies will implement an MDMS that will capture and manage the large amount of customer interval energy usage data obtained from the smart meters. This interval data will then be used to create more efficient and automated billing information so that customers can receive more timely monthly statements and obtain more detailed usage data through the CFS.

8. Outage Management System

An OMS is a computer system used by operators of electric distribution systems to assist in restoration of power. Major functions typically found in an OMS include: (1) prioritizing restoration efforts and managing resources based on various criteria such as locations of emergency facilities, and size and duration of outages; (2) providing information on the extent of outages and number of customers affected to management, media and regulators; (3) estimation of restoration times; (4) management of crews assisting in restoration; and (5) more efficient scheduling of crews required for restoration.

For the SGF Project, the Companies will be expanding their existing OMS at Hawaiian Electric on O‘ahu to Maui Electric and Hawai‘i Electric Light. This will be performed along with enhancements to usage information from the new smart meters and communications network to monitor and more quickly identify outages on the respective distribution systems. Expanding this functionality to Maui Electric and Hawai‘i Electric will provide more efficient restoration of service to customers more quickly than currently possible.

9. Customer Engagement

The SGF Project includes CE activities associated with incremental customer interactions, outreach and education. . As learned from other Smart Grid implementations, effective customer engagement is critical to a successful project, as Smart Grid introduces customers to new technologies, new options and additional information about their energy use. The Companies' Smart Grid customer engagement activities employ a variety of multi-channel engagement tools and tactics, including: (1) community outreach; (2) customer education; (3) government relations; (4) third-party engagement; (5) media relations; (6) customer research (and measurement); (7) employee engagement; and (8) customer service support. Details regarding these planned activities are provided in Exhibit C to the accompanying Application.

10. Project Management

The PMO consists of the following shared services provided across all SGF Project components above: (1) project governance; (2) cross-project coordination; (3) centralized procurement, contracts and vendor management; (4) project administration, support, controls and reporting; and (5) organizational change management and process improvement. In general, the PMO staffing will be at its highest in the first three years of the SGF Project implementation, and will taper off in the last two years as a majority of the SGF Project components are completed.

Since the PMO services are shared across all of the components of the SGF Project, the PMO costs have been allocated to each component based on their corresponding proportion of the overall SGF Project costs. For example, since the AMI costs represent roughly 55% of the overall SGF Project costs, roughly 55% of the PMO costs are allocated to the AMI subproject over its five-year implementation. These allocations are spread within each component by year, company and accounting treatment.

B. SGF PROJECT MANAGEMENT

In order to ensure that all the components of the SGF Project are executed smoothly and well-coordinated, the SGF Project will adhere to an overall project management process that includes a formal project organizational structure and governance.

1. Project Organizational Structure

The SGF Project organizational structure is illustrated in Figure 1 below, which shows the overall governing structure and different associated lead positions for each team to manage the component deployment during the SGF Project implementation.

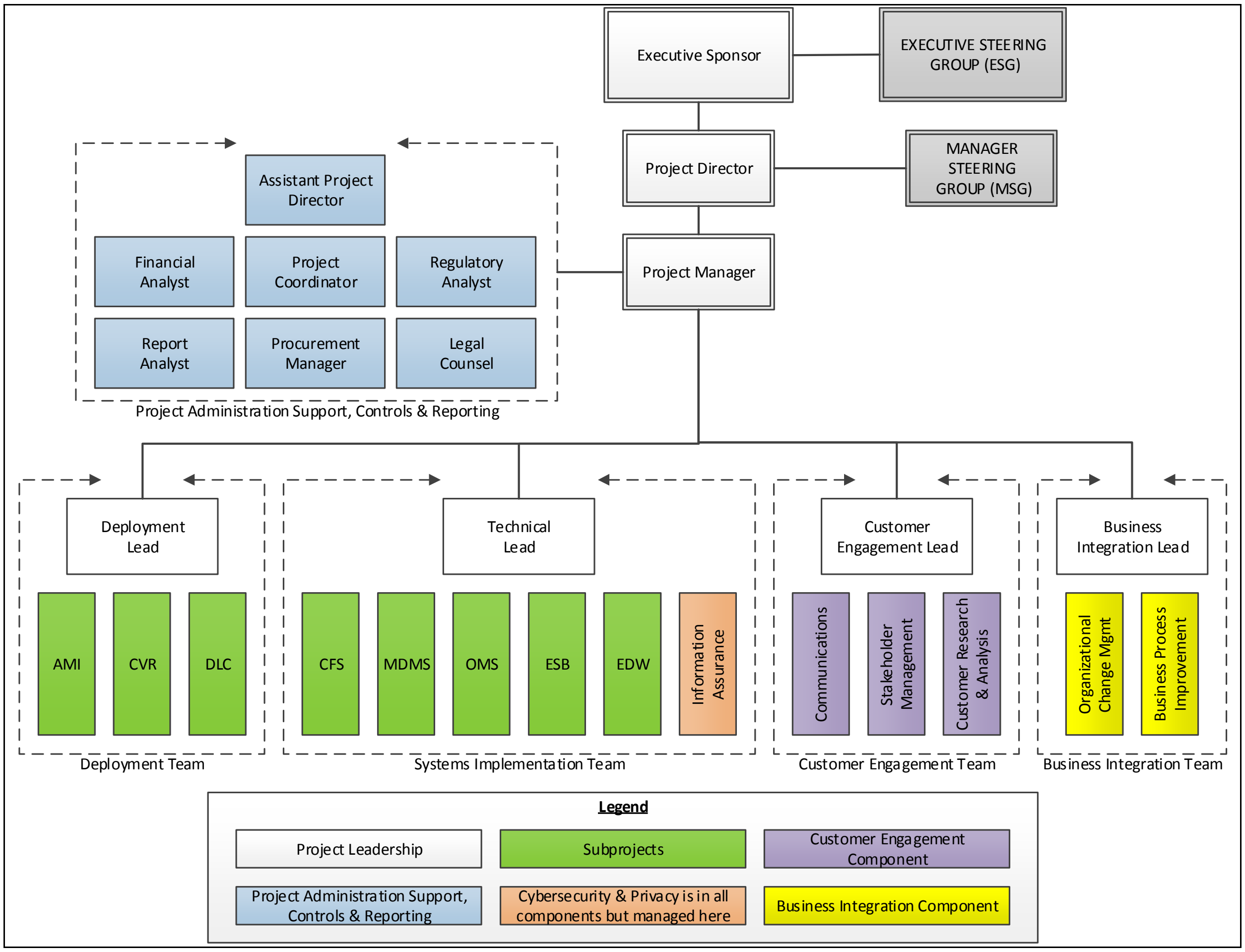

Figure 1

The project management portion of the structure consists of three major functions: (1) the project administration support, controls and reporting team; (2) the business integration team; and (3) the project leadership team. The following is a high-level description of each of the major functions.

The SGF Project administration support, controls and reporting team is responsible for providing project management support to the overall SGF Project. This includes supporting the project leadership in executing project management processes, including project coordination, scheduling, timekeeping, procurement, accounting, regulatory, budgeting and reporting activities.

The SGF Project business integration team is responsible for providing organizational change management and business process improvement support to the SGF Project subprojects. This includes coordinating the retirement of existing positions, while establishing new positions, and ensuring appropriate knowledge transfer and training. This team will also provide business process improvement coordination with existing as well as new processes established with the new Smart Grid solutions.

The SGF Project leadership team consists of:

a. ***Executive Sponsor and the Executive Steering Group***

The Executive Sponsor is the primary executive who is responsible for overseeing the entire SGF Project. This role ensures coordination at the executive level and provides executive level decision making for the project. The executive sponsor is also responsible for managing and facilitating key strategic decisions, and ensuring that executive level escalations are resolved in a timely manner.

The Executive Steering Group is a selected subset of the Chief Executive Officer's executive staff, which represents the primary interest of the process areas that are impacted by the SGF Project. It is divided into two groups: (1) a Core Executive Steering Group; and (2) an Extended Executive Steering Group. The Core Executive Steering Group meets regularly either weekly or bi-weekly (depending on need). It consists of the Chief Information Officer, Chief Financial Officer, President of Maui Electric, President of Hawai'i Electric Light, Senior Vice President of Customer Service, Vice President of Energy Delivery and Vice President of System Operations. The Extended Executive Steering Group includes the rest of the executive team and meets either once a month or quarterly (depending on need). Both groups in combination will provide cross-functional executive level vetting of issues and guidance to the Executive Sponsor and project team.

b. ***Project Director and Manager Steering Group***

The SGF Project will be led at the management level by a Project Director. The Project Director's primary responsibility and accountability is to the overall successful management of the project and ensuring that the project is carried out in accordance with the Smart Grid Roadmap and other projects outside of the SGF Project. This position is responsible for facilitating the various governing structures and making recommendations to these governing structures to achieve major senior management decisions.

Much like the Executive Steering Group, the Manager Steering Group provides guidance on the SGF Project implementation at the management level. They also act as an initial point of review prior to executive escalation. This ensures that ample input and insight is gained by the Project Director to facilitate and review at the manager level before escalation to executives.

c. ***Project Manager***

The Project Manager's primary responsibility and accountability is to manage the day-to-day activities of the SGF Project. This role ensures that all project management activities are well-managed and executed on-time, on-budget and on-quality. It also provides support the Project Director and acts as a back-up to the Project Director role as needed. This role is the primary supervisor to the Project Administration Support, Controls and Reporting Team and is the primary point of escalation for the rest of the project team leads.

d. Project Team Leads

There are four project team leads: (1) Deployment Lead; (2) Technical Lead; (3) Customer Engagement Lead; and (4) Business Integration Lead. The Deployment Lead heads up the AMI implementation, DLC replacement and CVR implementation. The Technical Lead heads up the CFS, MDMS, OMS, ESB, EDW and information assurance activities discussed in Section I.B.1.d above. The Customer Engagement Lead heads up all customer activities while coordinating with external third parties. The Business Integration Lead heads up the organizational change management and business process improvement activities.

2. Project Risk Management

Given the magnitude and importance of the SGF Project to customers and Hawai‘i's energy future, the Companies have taken great care to ensure that any potential risks to the project are mitigated to the greatest extent possible. As defined by the Project Management Institute ("PMI"), project risk is "an uncertain event or condition that, if it occurs, has a positive or negative effect on a project's objectives." Good project risk management depends on supporting organizational factors, clear roles and responsibilities, and technical analysis skills.

The Companies have identified the following five primary areas of potential risks to the SGF Project: (1) knowledge risk; (2) project execution risk; (3) technology risk; (4) operational risk; and (5) customer adoption risk.

a. Knowledge and Project Risks

Knowledge risk arises when deficient knowledge is applied to a situation. For the SGF Project, the Companies recognized the opportunity to learn from the experiences of other leading utilities and experts in the United States and around the world. The Companies have actively engaged with their industry peers, suppliers and consultants over the past five years.[5] Through several pilot projects,[6] they have gained considerable knowledge related to the opportunities and challenges associated with implementing a Smart Grid in Hawai‘i. Key members of the Companies' Smart Grid team are also members of various national Smart Grid user groups (e.g., SSNI User Group, EPRI Smart Grid, IEEE Smart Grid Consortium).

Project execution risk management (e.g., management of schedule, quality of deliverables, cost) addresses the individual risks at the project level that, if realized, will have a wider impact on related activities. In order to prevent SGF Project risks from impacting the Companies' broader Smart Grid and transformation initiatives, the Companies have followed industry best practices for similar projects, learned from other utilities, and developed a PMO as a result. The Companies will be employing PMI's methods for successfully managing programs such as Smart Grid, requiring their Smart Grid suppliers to have dedicated project managers who are PMI-certified.

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[5] These include but not limited to Maui Smart Grid pilot program, Kaua‘i Island Utility Cooperative, Florida Power & Light Company, Pacific Gas and Electric Company, Sacramento Municipal Utility District, Oklahoma Gas & Electric, Commonwealth Edison, American Electric Power, Black and Veatch, Corepoint 1 and Enernex.

[6] See Smart Grid Roadmap at 19, n.22.

b. Technology Risk

The Companies' Smart Grid and other transformational initiatives will increasingly tie new and emerging technologies to the Companies' critical business processes. In order to mitigate the potential impact of a SGF Project technology failure, the Companies have carefully selected proven technologies to be deployed through a thorough vetting process that included several lab tests and field demonstrations, such as the Initial Phase on O'ahu. The Companies have also begun to develop robust architecture and implementation plans that address the potential integration risks, both in terms of implementation as well as ongoing operations.

c. Operational Risk

At a high level, operational risk typically refers to the risk of loss resulting from inadequate or failed internal processes and systems, human factors or external events. In order to mitigate operational risks to the SGF Project, the Companies have planned activities for business process reengineering and organizational change management. This plan has been informed through discussions with leading utilities and subject matter experts with direct Smart Grid deployment and operational experience.

d. Customer Adoption Risk

As discussed in Exhibit C, prior Smart Grid implementations have shown that effective customer engagement is critical to a successful project, as Smart Grid programs introduce customers to new technologies, new options and additional information about their energy use. Engaging customers early and often has proven to be an effective way of mitigating customer adoption risk, with higher rates of customer acceptance. Toward that end, the Companies plan to introduce various facets of the SGF Project's solutions through a phased approach, emphasizing the customer-focused technologies through various forms of public customer engagement events throughout the implementation.

e. Vendor Risk

Vendor risk relates to the ability for the contracted vendors to deliver their products and services as expected. To a certain extent, vendor risks can be mitigated through contractual provisions that are designed to make the vendee whole in the event of a vendor failure. However, contractual provisions cannot insulate a vendee from every type of possible failure. For example, the financial failure of a vendor could result in the discontinuation of the vendor's product line or even loss of product support with little or no economic recourse for the vendee. For the SGF Project, the Companies have mitigated this though the RFP process outlined in Exhibit E by selecting vendors with proven track records, market presence and economic strength.

C. SGF PROJECT SCHEDULE

The SGF Project is scheduled to be implemented over five years beginning immediately upon the issuance of a decision and order enabling the project to commence, which is currently assumed to be in early 2017. Each component has its own schedule with its own commencement and in-service/go-live date(s) as illustrated in Figure 2 and further detailed in Section II.B, below.

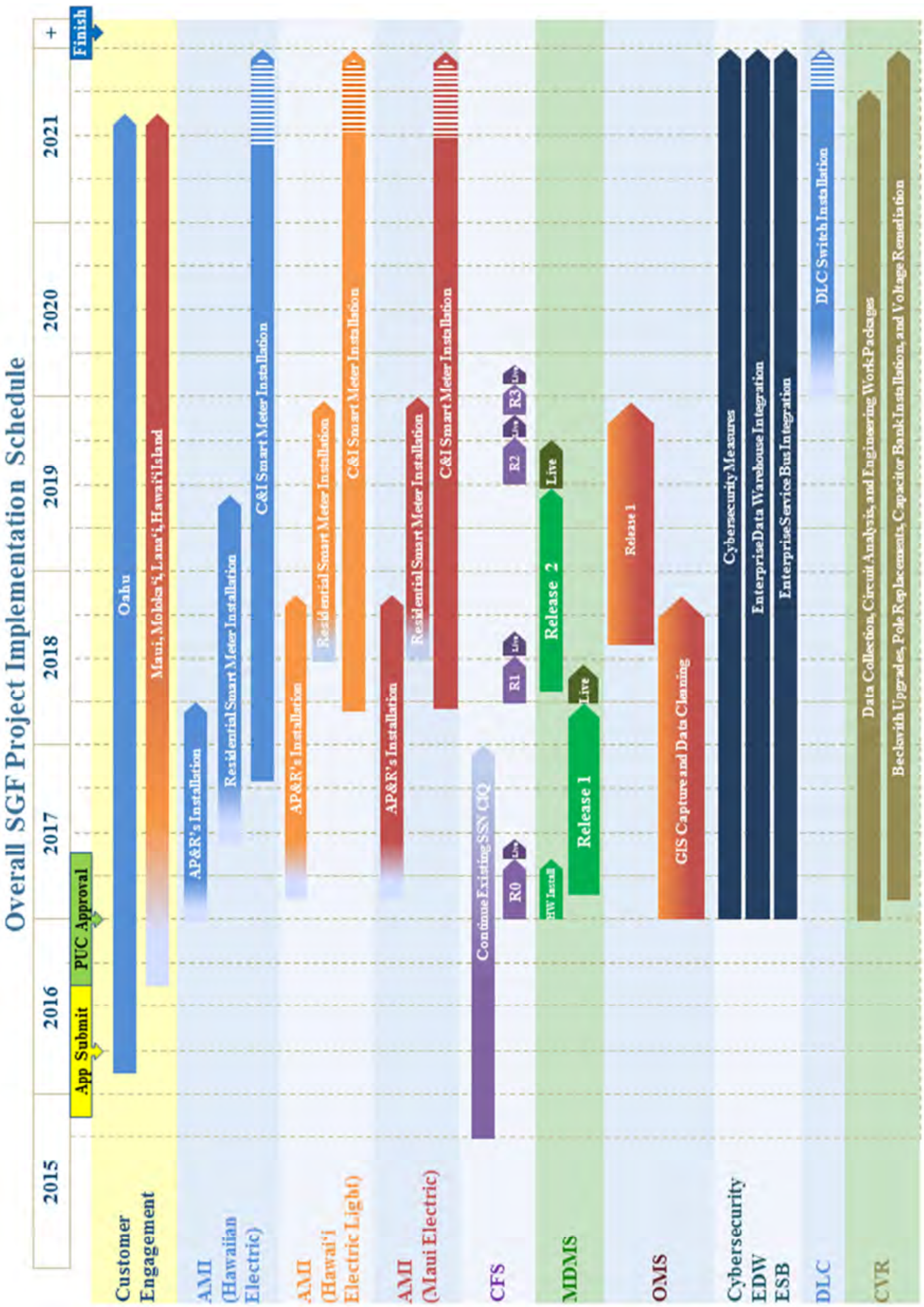

Figure 2

After the subprojects are placed in-service/go-live, there will be certain ongoing expenses (i.e., support, maintenance and lifecycle costs) as well as post-in-service costs related to the accelerated depreciation of the remaining book value of the Companies' existing non-smart meters. These ongoing expenses and post-in-service costs are not included in the SGF Project cost estimate. However, they are taken into account for purposes of the overall economic analysis of the SGF Project, as well recovery of relevant costs through the Modified REIP Framework as further described in Exhibit G to the accompanying Application. Further discussion of the ongoing expenses and post-in-service costs related to the SGF Project is provided below in Sections II.C and II.D, respectively.

II. SGF PROJECT COSTS

The total nominal cost of the SGF Project over its five-year implementation is estimated at $340 million. Table 1 provides a summary of the costs of the eight SGF Project subprojects and customer engagement component by accounting treatment for the consolidated Hawaiian Electric Companies. In order to show the total cost of each of these items, the costs for the PMO component are included in each of the components within the table. Details regarding the allocations of the PMO costs are provided in Attachment 1.

Hawaiian Electric Companies Consolidated Five-Year SGF Project Implementation Costs by Accounting Treatment (Nominal $000s)				
Component	Capital	Deferred	Expense	Total
AMI	162,814	2,229	20,819	185,862
CFS	15	6,102	2,796	8,912
CVR	21,758	1,201	3,902	26,861
DLC	17,913	615	942	19,470
EDW	6	4,548	5,617	10,172
ESB	996	5,327	4,208	10,531
MDMS	1,996	43,842	5,887	51,725
OMS	42	11,212	6,836	18,091
CE	9	-	8,403	8,412
Total	**205,549**	**75,077**	**59,409**	**340,035**
Note: Includes all applicable taxes, AFUDC and allocated PMO costs.				

Table 1

Table 2, Table 3 and Table 4 below provide a similar cost presentation broken out by utility and by accounting treatment. Information regarding what services are provided within the accounting treatment and component by utility are broken out per year in Attachment 2.

Hawaiian Electric Five-Year SGF Project Implementation Costs by Accounting Treatment (Nominal $000s)				
Component	Capital	Deferred	Expense	Total
AMI	99,396	2,229	13,635	115,260
CFS	15	6,102	2,796	8,912
CVR	11,791	1,201	2,533	15,526
DLC	17,913	615	942	19,470
EDW	6	4,548	5,617	10,172
ESB	996	5,327	4,208	10,531
MDMS	1,996	43,842	5,887	51,725
OMS	4	1,123	987	2,114
CE	9	-	6,668	6,676
Total	**132,126**	**64,988**	**43,272**	**240,386**
Note: Includes all applicable taxes, AFUDC and allocated PMO costs.				

Table 2

Hawai'i Electric Light Five-Year SGF Project Implementation Costs by Accounting Treatment (Nominal $000s)				
Component	Capital	Deferred	Expense	Total
AMI	36,133	-	3,562	39,695
CFS	-	-	-	-
CVR	5,423	-	756	6,180
DLC	-	-	-	-
EDW	-	-	-	-
ESB	-	-	-	-
MDMS	-	-	-	-
OMS	19	5,057	2,925	8,000
CE	-	-	868	868
Total	**41,576**	**5,057**	**8,110**	**54,742**
Note: Includes all applicable taxes, AFUDC and allocated PMO costs.				

Table 3

Maui Electric Five-Year SGF Project Implementation Costs by Accounting Treatment (Nominal $000s)				
Component	Capital	Deferred	Expense	Total
AMI	27,285	-	3,622	30,907
CFS	-	-	-	-
CVR	4,543	-	612	5,156
DLC	-	-	-	-
EDW	-	-	-	-
ESB	-	-	-	-
MDMS	-	-	-	-
OMS	19	5,033	2,925	7,976
CE	-	-	868	868
Total	**31,847**	**5,033**	**8,026**	**44,906**
Note: Includes all applicable taxes, AFUDC and allocated PMO costs.				

Table 4

As discussed in the Smart Grid Roadmap, when taken in their entirety, the overall bundle of benefits and capabilities enabled by Smart Grid in the Companies' service territories supports an overall positive business case that will increase capabilities and lower costs in the long run. However, due to economies of scale associated with the concentration of customers on O‘ahu, the business cases for implementing Smart Grid independently at Maui Electric and/or Hawai‘i Electric Light are not positive, while the business case for implementing Smart Grid independently on O‘ahu is positive.

Consistent with these economic realities, the Companies have allocated the costs of the CFS, EDW, ESB and MDMS subprojects 100% to Hawaiian Electric (since but for Hawaiian Electric none of these subprojects would be implemented at Maui Electric and Hawai‘i Electric Light). In other words, no costs are included for Hawai‘i Electric Light or Maui Electric, as these systems will be centralized at Hawaiian Electric on O‘ahu, and their utilization at Hawai‘i Electric Light and Maui Electric will not result in any incremental costs to the project. In addition, as discussed in Section II.B.4 below, no DLC costs are included for Hawai‘i Electric Light or Maui Electric because the EnergyScout water heater program is only available to Hawaiian Electric customers on O‘ahu.

A. COST-ESTIMATING METHODOLOGY

The cost estimating methodology applied in this analysis is derived from industry-standard project management guidelines and standard cost estimating techniques. The estimates have been further validated where practicable with secured negotiated cost quotes developed from several requests for proposals ("RFPs") already instituted prior to the submission of the accompanying Application.[7] The cost estimates also take into account responses to requests for information ("RFIs") and pricing in the Companies' existing contracts with select vendors associated with equipment, software licensing, outside services, maintenance and training.

[7] See Exhibit E to the accompanying Application. The RFP awards are conditioned upon the issuance of a decision and order that enables the project to commence.

1. SGF Project Costing Assumptions

The general costing assumptions for the SGF Project are listed below:

- The SGF Project is expected to commence in January 2017 and be completed in December 2021.
- The SGF Project staff will be a combination of on-site and off-site (i.e., out-of-state) resources, including internal staff/employees, and/or external contractors and consultants.
- External vendors and consultants will provide their own computing equipment which will be connected to the Companies' network via restricted and controlled access. All security requirements will be validated before granting access.
- No costs for end-user computers (i.e., laptops or desktops) or their associated standard software for the internal employees who will be assigned to the SGF Project are included in the cost estimates. Costs for new end-user computers for new employees assigned to the project (both temporary and permanent) are included in the project costs.
- In general, to the extent internal labor resources assigned to the project are already included in base rates, the SGF Project cost estimate excludes the costs of such labor. See Attachment 3.
- Internal labor hours are based on loaded labor rates, which consist of standard labor rates (which vary depending on the associated labor class) and associated overhead allocations as of September 2014. See Attachment 4.
- Stores overhead is applied to all procured equipment and hardware according to the rates in Table 5 below, as of January 2016. The forecasted rate used for the years beyond 2018 utilizes the same rate from 2018.

Company\Year	2016	2017	2018
Hawaiian Electric	0.198	0.099	0.103
Hawai'i Electric Light	0.249	0.186	0.107
Maui Electric	0.175	0.128	0.139

Table 5

- Loaded labor rates are escalated at a rate of 3% annually for non-bargaining unit employees, 3% annually for bargaining unit employees through 2018, and 1.5% annually for bargaining unit employees after 2018.

- 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 for which only a base price was provided for the relevant first year (e.g., SSNI professional services and CVR equipment) and which are not fixed by contract are escalated using the Gross Domestic Product Price Index ("GDPPI") as of October 2015 of 1.8% annually.

- A standard allowance for funds used during construction ("AFUDC") calculation escalated for years one through five is used, and applied to all capital and deferred costs (exclusive of smart meters, computer hardware, and their installation and other related costs). Table 6 below shows the rates utilized for the AFUDC calculations by company and year.

AFUDC Escalation Rates by Year					
Company	2017	2018	2019	2020	2021
Hawaiian Electric	8.19%	8.20%	8.28%	8.28%	8.28%
Hawai‘i Electric Light	7.89%	7.89%	7.89%	7.89%	7.89%
Maui Electric	7.28%	7.28%	7.28%	7.28%	7.28%

Table 6

A breakout of the AFUDC (consolidated) by component is provided in Table 7 below.

SGF Project AFUDC Implementation Costs by Component (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
AMI	731	622	386	22	9	1,769
CFS	99	52	78	57	-	286
CVR	213	263	128	91	132	828
DLC	14	37	-	-	-	51
EDW	52	31	34	38	24	180
ESB	107	23	24	25	31	210
MDMS	697	1,946	1,168	-	-	3,811
OMS	-	133	531	-	-	665
CE	-	-	-	-	-	-
Total	**1,913**	**3,108**	**2,351**	**232**	**196**	**7,801**

Table 7

2. Component Cost Categories

The costs for each component are generally broken down into the following eight cost categories: (1) Equipment; (2) Hardware; (3) Internal Labor; (4) Maintenance; (5) Miscellaneous; (6) Outside Services; (7) Software; and (8) AFUDC. The costs by year that the Companies expect to incur under each of these cost categories are shown in Table 8, below. Details specific to each of these costs categories as they relate to the individual components are provided in Section II.B below.

SGF Project Total Implementation Costs by Cost Category (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Equipment	18,165	34,799	23,480	7,335	8,007	91,785
Hardware	3,350	116	-	-	236	3,701
Internal Labor	12,284	21,521	20,399	10,711	9,290	74,205
Maintenance	4,402	5,014	4,971	2,849	2,657	19,893
Misc.	541	410	422	156	137	1,666
Outside Services	45,230	38,567	31,068	10,107	8,097	133,070
Software	6,551	1,363	-	-	-	7,913
AFUDC	1,913	3,108	2,351	232	196	7,801
Total	**92,437**	**106,149**	**87,002**	**42,196**	**41,175**	**340,035**

Table 8

a. Equipment

The equipment cost category of the SGF Project, which totals approximately $92 million, includes the necessary devices and equipment required for the installation and implementation of specific Smart Grid infrastructure. The equipment costs are allocated within the AMI, CVR and DLC subprojects.

b. Hardware

The hardware cost category, which totals approximately $4 million, includes costs for computer hardware, computer network switches and computer security devices. The hardware costs are allocated within the AMI, CVR, EDW, ESB, MDMS and OMS subprojects.

c. Internal Labor

The internal labor cost category, which totals approximately $74 million, includes the costs for internal employee effort on all of the components.[8] These costs are incremental and not double counted in existing base rates. Among other things, internal employees are needed to work on the project so that the new processes and capabilities will be maintained and retained within the Companies over the long term. A consolidated view of the SGF Project internal labor by company, cost component and accounting treatment is provided in Attachment 3.

[8] The internal labor estimate of $74 million, and also the outside services estimate of $133 million as discussed in Section II.A.2.f includes preliminary engineering costs related to AMI Network Design and CVR engineering. SSNI was contracted in 2015 to perform a preliminary AMI Network design for all five islands. The purpose of the AMI Network Design is to identify the number of Access Points ("APs"), Relays and Micro APs required for each island.

d. ***Maintenance***

The maintenance cost category, which totals approximately $20 million, includes the cost of software license maintenance, firmware maintenance and software-as-a-service ("SaaS") as the various components of the SGF Project are installed and activated. The maintenance costs are allocated within all of the subprojects.

e. ***Miscellaneous***

The miscellaneous cost category, which totals approximately $2 million, includes costs associated with travel expenses, furniture, office supplies, equipment (e.g., computers, end user software, printers) and office space, that are needed to support the incremental labor resources assigned to the various SGF Project components. The descriptions for these costs are generally the same for each SGF Project component.

f. ***Outside Services***

The outside services cost category, which totals approximately $133 million, includes costs for externally acquired resources needed to complete the subprojects. This consists of vendor supplied system integrators (e.g., SSNI, MDMS vendor), third-party installers (i.e., Corix) and contract labor resources (e.g., project managers, temporary customer service representatives ("CSRs"). These resources are needed due to the complexity of the project, the time constraints involved, and the lack of sufficient workforce or expertise currently available within the Companies. For example, the Companies do not have adequate internal labor resources to integrate the new AMI, CFS, EDW, ESB, MDMS and OMS solutions with other systems such as the SSNI head end,[9] SAP Customer Information System ("CIS"), SSNI meter Outage Detection System ("ODS") on Oʻahu or Energy Management Systems ("EMS") at Maui Electric and Hawaiʻi Electric Light. As a result, some of this integration work will need to be performed by outside consultants.

A consolidated view of the SGF Project outside services by company, component and accounting treatment is provided in Attachment 5.

g. ***Software***

The software cost category, which totals approximately $8 million, includes the cost for software licensing fees associated with the various software products that will be implemented in connection with the CVR, ESB, MDMS and OMS subprojects.

B. SGF PROJECT COMPONENT COSTS AND SCHEDULES

Table 9 below provides a breakdown of the $340 million of SGF Project costs by cost category and project component.[10]

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[9] The SSNI head-end is a centralized application that connects the AMI field network to a data center.
[10] The estimates provided in this section are presented in nominal dollars (i.e., they have not been discounted to reflect the time value of money). Although Table 9 includes AFUDC, the values presented in Sections II.B.1

Total SGF Project Implementation Costs by Cost Category and Component (Nominal $000)									
Component	Equipment	Hardware	Internal Labor	Maintenance	Misc.	Outside Services	Software	AFUDC	Total
AMI	81,750	1,560	43,484	[redacted]	501	51,938	-	1,769	185,862
CFS	-	-	1,250	1,056	67	6,254	-	286	8,912
CVR	2,059	71	14,190	3,195	101	4,858	1,559	828	26,861
DLC	[redacted]	-	1,063	[redacted]	38	[redacted]	-	51	19,470
EDW	-	-	2,019	[redacted]	56	[redacted]	-	180	10,172
ESB	-	[redacted]	1,657	[redacted]	56	[redacted]	[redacted]	210	10,531
MDMS	-	1,565	5,766	[redacted]	539	33,468	[redacted]	3,811	51,725
OMS	-	-	2,733	[redacted]	217	[redacted]	[redacted]	665	18,091
CE	-	-	2,045	-	90	6,277	-	-	8,412
Total	**91,785**	**3,701**	**74,205**	**19,893**	**1,666**	**133,070**	**7,913**	**7,801**	**340,035**
Note: PMO costs allocated to individual components									

Table 9

Sections II.B.1 through II.B.10 below provide detailed descriptions of each respective component of the SGF Project, along with its related costs for implementation.

1. Advanced Metering Infrastructure

The purpose of the AMI is to provide a two-way communications capability between the Companies and customer premises, which will enable the Companies to obtain energy consumption reads and voltage statuses at individual premises more frequently and accurately than existing manual monthly meter reading cycles and grid infrastructure capabilities permit. AMI also introduces enhanced functionalities that will allow for on-demand features that are not available with the manual processes the Companies currently have in place, such as remote disconnects and reconnects, temperature monitoring, remote meter reading and voltage control.

The Companies will utilize SSNI's communication network as the platform for AMI, transferring information between the Companies and their customers through the newly established neighborhood area network ("NAN"). This strategy will enable the nearly 467,000 smart meters installed to communicate with the Companies' back office and other Smart Grid solutions (e.g., EDW, ESB and MDMS) for a more efficient and sustaining data transfer system.

a. AMI Deployment Schedule

The scope and timeline to deploy the various AMI equipment and hardware components is phased beginning with enhanced cybersecurity software across the Companies' systems

through II.B.10 below do not include AFUDC, in order to provide a clearer illustration of the underlying nominal costs.

immediately upon commencement of the SGF Project. This is a necessary component to ensure that the AMI network will be secure and that customer information is protected.[11]

The Companies will deploy APs (access points) and relays to communicate the usage data obtained from the smart meters to the Companies' MDMS, ESB and EDW systems. Deployment of the APs and relays is scheduled to begin in early 2017, completing these installations on O'ahu approximately one year later, and subsequently completing on Maui, Moloka'i, Lana'i and Hawai'i Island toward the end of 2018. As the APs and relays are installed, the Companies will also begin their phased installations of the smart meters to follow in the geographic areas that have the APs and relays already activated, since these are required for the smart meters to communicate with the Companies' back office systems.

Residential smart meters are then scheduled to be deployed, beginning with O'ahu in mid-2017 and then commencing on Maui, Moloka'i, Lana'i and Hawai'i Island starting in mid-2018. The residential meter installation will take approximately 24 months to complete on O'ahu, and 18 months to complete on Maui, Moloka'i, Lana'i and Hawai'i Island, with the overall installation being completed by the end of 2019.

Concurrent with the residential meter installations, commercial and industrial ("C&I") meters will be installed using a similar approach, beginning with O'ahu in late 2017 and then commencing on Maui, Moloka'i, Lana'i and Hawai'i Island in early 2018. The C&I meter installation will take approximately 48 months to complete on O'ahu, and 36 months to complete on Maui, Moloka'i, Lana'i, and Hawai'i Island, with the overall installation being completed in late 2021. The overall deployment schedule for the AMI subproject is illustrated in Figure 3, below.

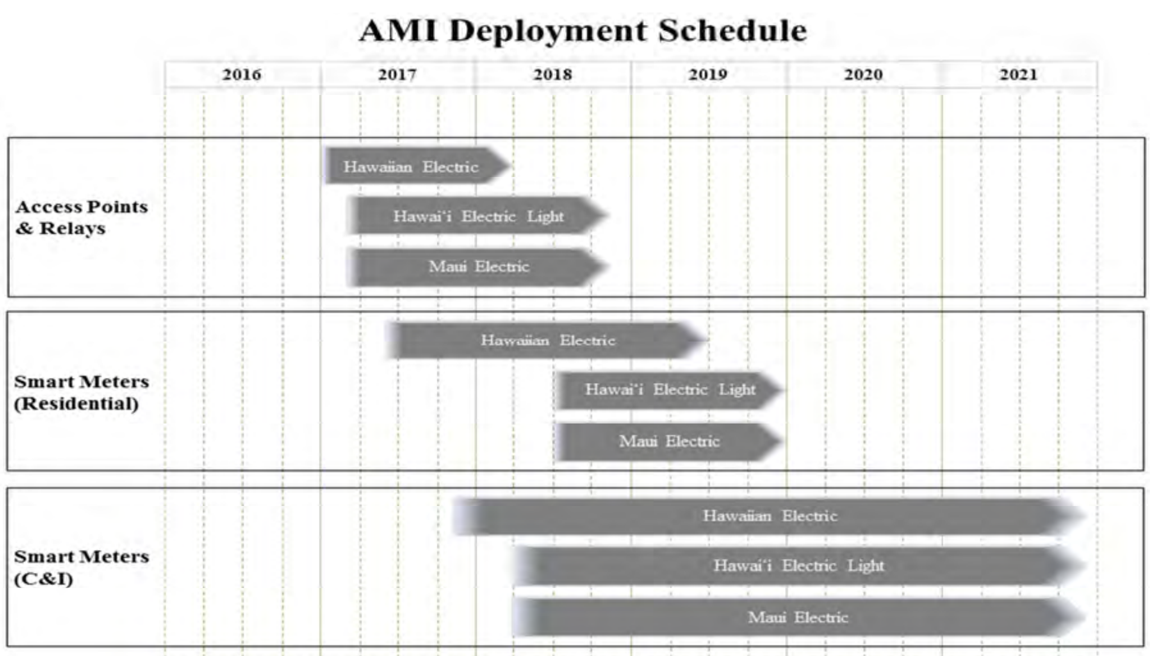

Figure 3

[11] See Exhibit D, Attachment 5 to the accompanying Application for additional information regarding the Companies' process for enhancing their cybersecurity tools during the SGF Project implementation.

This phased approach for the AMI subproject is being utilized to make the implementation more efficient and mitigate execution risks, as well as to ensure, validate and if necessary, troubleshoot, the AMI infrastructure prior to any subsequent subprojects being implemented (e.g., MDMS, OMS).

b. AMI Costs

The total estimated cost of the AMI subproject implementation is estimated to be $184 million, as summarized by cost category in Table 10, below.

AMI Subproject Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Equipment	18,049	34,508	23,259	2,915	3,018	81,750
Hardware	1,324	-	-	-	236	1,560
Internal Labor	6,253	12,586	12,356	7,047	5,241	43,484[12]
Maintenance	1,714	1,455	1,000	342	350	4,860
Misc.	149	93	92	84	82	501
Outside Services	22,279	14,631	11,477	2,197	1,355	51,938
Total	**49,768**	**63,273**	**48,185**	**12,585**	**10,282**	**184,092**

Table 10

The AMI subproject consists of equipment, hardware, internal labor, maintenance and miscellaneous costs, as further detailed in the following sections.

i. AMI Equipment

The estimated cost of the equipment for the AMI subproject is approximately $81.8 million, and is broken out by year as detailed in Table 11, below.

[12] Includes $6,952,000 of incremental costs of internal labor resources, the cost of which are currently included in base rates as expense, and which have been reclassified as capital or deferred costs and included as a benefits offset for purposes of surcharge recovery under the Modified REIP Framework, as explained in Section IV.C.6 below.

AMI Subproject Equipment Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Meters, NICs, Materials	16,507	29,167	19,766	2,915	3,018	71,373
APs and Relays	928	2,917	1,804	-	-	5,650
Pole Replacements	613	2,424	1,689	-	-	4,727
Total	**18,049**	**34,508**	**23,259**	**2,915**	**3,018**	**81,750**

Table 11

The majority of the AMI equipment costs are for the smart meters and network interface cards ("NICs") to connect the various devices over the wireless AMI network. The Companies issued an RFP for the smart meters, and the estimated costs are based on the Landis + Gyr (L&G) proposal.[13] The NIC cost estimates were provided by SSNI.

The Companies will need to install APs and relays throughout their service territories in order to extend the range for the deployed smart meters to communicate with the Companies' back office systems. The estimated cost for the installation of these devices was calculated assuming the need to accommodate communication difficulties that may arise, depending on where the smart meter is installed. The Companies have assumed that 40% of the AP and relay locations would require a pole change out in order to meet the Commission's General Order No. 6[14] and National Electrical Safety Code[15] standards when installing the new equipment on poles. The correlating costs for the pole replacements will be incurred during the first three years of the AMI subproject.

The Companies will also utilize box housings from TESCO Technologies, Inc., which are enclosures that will be installed on the poles to house the APs and relays for protection and ease of maintenance. The housings will include other electronic boards and batteries that allow the APs and relays to operate should the poles on which they are installed experience a power outage. The AMI equipment cost estimate also includes costs for 460 Micro APs that will be needed for installation in certain areas on Maui and Hawai'i Island (149 and 311, respectively) where the terrain makes it more difficult to connect via the standard wireless APs and relays.

The Companies have also allocated costs specific to the replacement of meter sockets, which are typically costs incurred by the customer. As part of the SGF Project implementation, the Companies plan to replace any damaged meter sockets in lieu of requiring customers to repair or replace the damaged sockets themselves. This alternative is being proposed in order to avoid the potential deployment lag that will occur in the event of a needed meter socket replacement. It also alleviates the additional cost to the customer of approximately $1,000 per

[13] See Exhibit E, Attachment 1 to the accompanying Application.
[14] See General Order No. 6, Section 1, *Rules for Overhead Electric Line Construction*.
[15] See IEEE Standard C57.12.29-2014, *IEEE Standard for Pole-Mounted Equipment*, updated December 29, 2014.

replacement. The costs of these sockets are included in the AMI subproject equipment cost estimate at a total of approximately $1.4 million.[16]

ii. AMI Hardware

As shown in Table 12 below, the estimated hardware cost of the AMI subproject is approximately $1.6 million, primarily consisting of costs for hardware needed for the AMI cybersecurity segmentation required to secure information traffic coming through the new AMI network. The Smart Grid will introduce new systems and new data sets into the Companies' data environment. Consequently, additional "defense-in-depth" work is needed to enable the new data flows while adding protections against cyber-threats inherent in a more interconnected systems environment. This work will include installation of several additional, high bandwidth and redundant firewalls at strategic points in the Companies' data network. It will also involve expanding the security event logging and log analysis capabilities already deployed within the Companies. This work will also include activities related to implementation of the Smart Grid Data Voluntary Code of Conduct recently promulgated by the United States Department of Energy.

AMI Subproject Hardware Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Security Encryption Keys, Segmentation & Firewalls	1,324	-	-	-	236	1,560
Total	**1,324**	**-**	**-**	**-**	**236**	**1,560**

Table 12

iii. AMI Internal Labor

The estimated $43.5 million cost of internal labor for the AMI subproject is based on the efforts summarized in Table 13, below. The cost estimate is based on an anticipated internal labor requirement of 540,000 hours over the five-year implementation of the subproject.

[16] A discussion of the Companies' request to waive to waive, for residential purposes only, the Tariff Rule 14 requirement for each company that the customer furnish, install, and maintain meter sockets, during the SGF Project implementation period is provided in the accompanying Application.

AMI Subproject Internal Labor Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Meter Installation	3,122	7,366	7,263	3,772	2,217	23,740
Meter & Network Support	106	756	1,436	2,370	2,279	6,947
APs & Relays Installation	822	2,948	2,223	75	-	6,068
PMO	854	984	978	508	413	3,737
Cyber-Security	597	531	457	322	332	2,239
Preliminary Engineering	711	-	-	-	-	711
Meter Device Inventory SW Integration	26	-	-	-	-	26
Data Warehousing	14	1	-	-	-	15
Total	**6,252**	**12,586**	**12,357**	**7,047**	**5,241**	**43,483**

Table 13

The AMI internal labor estimates above include incremental costs for internal labor to install the SSNI network and smart meters, fill new positions as a result of the AMI implementation, install the cybersecurity measures for the SSNI network and install the data warehousing components that will house the collected smart meter data. These estimates are based on assumptions regarding the number of positions required and the annual hours per position during the SGF Project. The estimate takes into account the number of poles the Companies will need to replace, and the number of APs and relay locations with their associated labor requirements. Each island has a different work process and accompanying positions tasked with issuing job packages and performing their subsequent installations. The Companies utilized these variations to more accurately estimate the labor costs, by island, and then consolidated them to arrive at the total costs presented above.

Once a smart meter is installed, the Companies will need to ensure that it goes into an active state in order to collect the interval energy usage data through a validation process (see Section II.B.1.a above). New positions are required to monitor and maintain the active states of all the smart meters. The total cost for these new positions includes costs for the personnel required to monitor the states of the smart meters and the staffing necessary to troubleshoot communication issues with the smart meters as they arise.

Internal labor will also be necessary for integration of the needed cybersecurity software and monitoring. This includes the setup of the segmentation of the systems and incremental labor for installing the data warehouse specific to the AMI portion of the EDW subproject, and loading the existing AMI information from the Initial Phase into the EDW solution.

There are also internal labor costs specific to preliminary engineering for the SGF Project application development, which have been allocated to the first year of deployment, and represent costs incurred by full-time equivalents ("FTEs") that developed the application. These costs were applied to the SGF Project since they were incremental positions that are not recovered through existing rate cases.

The PMO costs within the AMI subproject are related to the overall organizational structure of the SGF Project and the related Project Manager(s) that will be overseeing the AMI deployment across all five islands within the Companies' service territories. Additional discussion regarding these PMO costs is provided in Attachment 1.

Certain costs that have not been included in the AMI subproject estimate are typically part of the Companies' meter exchange process. These costs are specific to the testing and validation of meters in compliance with the Commission's General Order No. 7 ("G.O. 7") and American National Standards Institute ("ANSI") testing requirements to ensure that all deployed meters are functioning properly and accurately, and that the usage data is being accurately billed. For the SGF Project, the Companies have excluded these costs, instead categorizing them as avoided costs quantified as part of the overall economic analysis (see Section III below). The Companies plan to test existing digital meters that will be reused by customers electing to participate in the Companies' proposed Non-Standard Meter ("NSM") Service Tariff,[17] but the annual in-service performance testing costs have not been included as part of the SGF Project costs estimated herein. The Companies are proposing a waiver of these standard requirements for all meters during the AMI subproject implementation.[18]

As existing non-AMI meters are replaced with smart meters it is expected that, the Companies will find certain older non-AMI meters that may tend to be inaccurate (slow/fast) due to the mechanical components within them wearing out. Although the Companies cannot predict exactly how many of these are currently still in use (and subsequently leading to inaccurately low/high bills), the Companies are requesting to waive back-billing processes during the SGF Project implementation, except in the event that a customer was overcharged, in which case a credit on the customer's account will be issued for the amount owed.[19]

iv. AMI Maintenance

As summarized in Table 14, below, the AMI subproject maintenance implementation cost estimate of approximately [redacted] million consists of costs for: (1) SSNI AMI SaaS fees; (2) SSNI SaaS cybersecurity fees; and (3) SSNI firmware maintenance, which ensures the ability to update each AP, relay and AMI NIC (i.e., the NIC contained in the smart meter) with the latest firmware software available. These services are necessary to ensure the equipment deployed as part of the AMI subproject are supported and maintained in accordance with the manufacturer's requirements.

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[17] See Exhibit H to the accompanying Application.
[18] See Section XI.A of the accompanying Application.
[19] See Section XI.B of the accompanying Application.

AMI Subproject Maintenance Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
[redacted]						
Total	[redacted]					

Table 14

v. AMI Outside Services

The outside services cost estimate for the AMI subproject implementation of approximately $51.9 million includes costs for the external vendor's (Corix) meter installation labor, SSNI costs, SSNI AMI segmentation, SSNI security installations and data warehousing integration. Table 15 below presents these costs over the five-year life of the SGF Project.

AMI Subproject Outside Services Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Meter Installation	[redacted]					
Network Installation Support						
Performance and Cyber-Security	2,965	1,061	938	1,140	1,062	7,166
Preliminary Engineering	6,401	-	-	-	-	6,401
Meter Installation Work Order Mgt. System Integration	[redacted]					
Network Design and Installation	740	941	516	-	-	2,197
PMO	460	528	524	295	45	1,852
Data Warehousing	1,152	309	-	-	-	1,461
Cellular Service	[redacted]					
Total	**22,280**	**14,631**	**11,475**	**2,197**	**1,354**	**51,937**

Table 15

[20] The decrease in fees in the latter years of the subproject is attributable to the fees being transitioned into ongoing costs.

The majority of the AMI subproject outside services cost are for the awarded RFP vendor, Corix, to install the residential smart meters across of the Companies' service territories. Corix will be providing labor to integrate their Work Management System ("WOMS") (needed to effectively communicate with customers and monitor and track smart meter installations) into the Companies' CIS, a WOMS to prioritize meter installation work for the installers (unionized Hawai'i licensed electricians), a staffed call center with both local and mainland CSRs to respond to customer inquiries specific to smart meter installations, warehouse storage for the smart meters, transportation for the contract meter installers and supervision/quality control for the meter installations.

The cost estimate for SSNI services to assist the Companies with the meter installation and providing the on-the-job training for monitoring meters includes costs for providing a full-time project manager over the duration of the residential smart meter installations, a Smart Grid engineer who provides technical expertise at the Companies' offices for meter management, a network engineer who will provide technical expertise for field personnel and SSNI personnel for completing the SSNI network design and optimization. The SSNI design work is already in progress as part of preliminary engineering, and is not included proposed surcharge under the Modified REIP Framework. However the optimization of this design is included in the AMI capital cost that will be incurred during the first three years of the AMI subproject. The total outside services cost includes the cost of services from SSNI to provide the Companies with the enhanced SSNI network design and application support as well, together with the PMO and installation assistance referred to under SSNI's "Professional Services" categorization.

As indicated above, Corix will provide labor for WOMS integration. However, additional outside services will be required to assist the Companies' Information Technology ("IT") organization in configuring the existing CIS for the WOMS integration. The total cost represents an estimated amount required to hire developers to perform the SAP configuration and integrate Corix's WOMS, incurred in the first year of the AMI subproject.

The cost to implement necessary security solutions consists primarily of external labor required to perform the hardware installations as well as labor required to maintain the systems as they are placed into service, including services to monitor cyber-threats on the Companies' system. The AMI outside services cost estimate also includes costs for the integration of data warehousing for AMI. This includes costs for external services required to configure the data warehousing component to receive the AMI data.

The Companies will also continue to use their existing external vendor, Verizon, as their cellular carrier throughout the AMI implementation.

2. <u>Customer Facing Solutions</u>

The purpose of the CFS subproject is to provide customers with the best possible experience using the value-added tools and services enabled by Smart Grid. In March 2015, the Companies issued an RFP for the CFS and, after an extensive evaluation process, selected Smart Utility Systems ("SUS") as the winning vendor.[21] The CFS will create a more interactive and

[21] <u>See</u> Exhibit E, Attachment 4 to the accompanying Application.

customer-focused electronic customer portal (i.e., web and mobile) that will enable customers to manage and access their energy bills and usage data in 15-minute intervals to better manage their energy consumption and electricity expenses, enroll in new programs enabled by smart meters (e.g., TOU rates), and allow for automated service notifications and outage alerts/updates, as well as many other customer-centric functionalities that will arise as the Smart Grid evolves.

a. CFS Deployment Schedule

The Companies will be introducing CFS to customers through four separate phases so that the transition from the existing online energy portal currently available to Initial Phase customers is seamless, and all technological and functional requirements have been tested and verified prior to each release. This will ensure that customers benefit from the CFS immediately as each component is released.

During the first phase of the CFS implementation, the core functionality will be configured and integrated with the Companies' CIS. The primary functionalities enabled during this phase include guest access, customer account registration, account authentication, development of the online account landing page, customer preference designations, service/account alerts, multiple-account modification/access and overall customer account display. This phase will take approximately 16 weeks to deploy, with an anticipated commencement in early 2017 and completion by late spring 2017, followed by a six-week stabilization and validation period.

The second phase of the CFS subproject will focus on integrated features and functions into the customer portal that are specific to interval data collection and access. These include but are not limited to general usage data, interval data on the Companies' various programs (e.g., TOU), billing and payment options for customer accounts and providing customers access to their "Green Button" data.[22] This phase will also take approximately 16 weeks to complete, with an assumed commencement in spring 2018 and completion in summer 2018, with a six-week stabilization and validation period.

The third phase of the CFS implementation will specifically address features and functions that leverage the full AMI capabilities, including but not limited to automated processes such as remote connect and disconnect. The primary features enabled during this phase will include providing customers the ability to make service requests (e.g., service start or stop) and the ability for customers to enroll in specific programs (e.g., TOU). This phase will take approximately 14 weeks to complete, with an assumed commencement in summer 2018 and completion by early fall 2018, followed by a six-week stabilization and validation period.

The fourth and last phase of the CFS subproject will integrate features and functions specific to the Companies' outage communications for customers through their individual online customer portals. This phase will take approximately eight weeks to complete, with an assumed

[22] As explained at www.greenbuttondata.org, all electric users have meters that are used to measure how much energy they use. This metered data is used by energy service providers to calculate how much that energy will cost consumers. Green Button makes that data available to consumers for planning and analysis.

commencement in fall 2019 and completion by early 2020, followed by a six-week stabilization and validation period.

Figure 4 below shows the overall CFS implementation schedule, as described above.

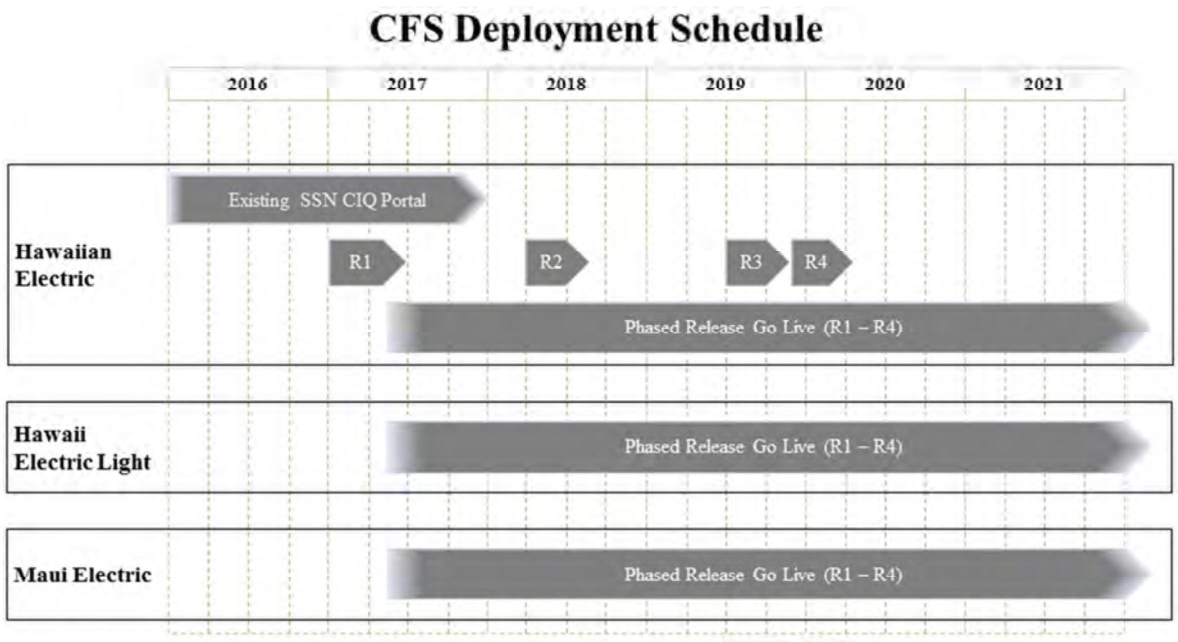

Figure 4

b. ***CFS Costs***

The total nominal cost for the CFS subproject is approximately $8.6 million, as summarized in Table 16, below:

CFS Subproject Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Internal Labor	479	202	282	287	-	1,250[23]
Maintenance	394	220	220	220	-	1,056
Misc.	39	13	14	1	-	67
Outside Services	2,474	1,515	1,887	378	-	6,254
Total	**3,385**	**1,951**	**2,403**	**886**	**-**	**8,626**

Table 16

[23] Includes $248,000 of incremental costs of internal labor resources, the cost of which are currently included in base rates as expense, and which have been reclassified as capital or deferred costs and included as a benefits offset for purposes of surcharge recovery under the Modified REIP Framework, as explained in Section IV.C.6 below.

The majority of the CFS subproject costs are for outside services due the fact that SUS (external vendor) is providing the technology and software that will be used to enhance customers' online and mobile experience. The cost breakouts for each cost category above are further detailed below.

i. CFS Internal Labor

The internal labor costs, estimated at $1.3 million (or 16,000 hours) for the CFS subproject, represent costs for staff to manage the implementation of the CFS throughout its four phases of deployment, and to perform the integration work between SUS and other systems, as further described in the outside services section below. Table 17, below, provides a further breakdown of the internal labor costs of the CFS subproject by phase:

CFS Subproject Internal Labor Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Management, Development, Integration, Testing	214	90	138	23		465
Training, Stabilization	212	84	100	227	-	623
PMO	53	28	45	36	-	162
Total	**479**	**202**	**282**	**287**	**-**	**1,250**

Table 17

ii. CFS Maintenance

As shown in Table 18 below, the estimated $1.1 million for the CFS maintenance cost includes costs for SUS to maintain the CFS over the five-year life of the SGF Project, as well as costs for SSNI to maintain the existing online customer energy portal until it is replaced by the new CFS solution.

CFS Subproject Maintenance Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
CFS Maintenance Fees	[redacted]					
CIQ Maintenance Fees						
Total	**394**	**220**	**220**	**220**	**-**	**1,056**

Table 18

iii. CFS Outside Services

As shown in Table 19 below, the outside services costs of approximately $6.3 million for the CFS subproject include costs for SUS to configure the SUS software per the requirements in the CFS RFP for each phased release (see Exhibit E, Attachment 4). This cost category also includes consultant costs to perform the integration and manage the implementation process.

CFS Subproject Outside Services Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Management, Development, Integration, Testing	2,148	1,152	1,692	199	-	5,191
Training, Stabilization	294	346	169	156	-	966
PMO	32	17	27	22	-	97
Total	**2,474**	**1,515**	**1,887**	**378**	**-**	**6,254**

Table 19

3. Conservation Voltage Reduction

CVR uses voltage measurements from smart meters obtained over an AMI network to enable system operators to more accurately and dynamically control voltage on distribution circuits, thus reducing energy usage and customer bills. CVR leverages the smart meters and the AMI network to collect and control meteorological data that is used in coordination with other operational data to obtain voltage optimization across the system. This will help to manage voltage fluctuations due to customer-sited DG.

In the absence of CVR, utilities have typically operated with voltage levels higher at the beginning of the circuit near the substation, where voltages are transformed from transmission voltages to distribution level operating voltages. The CVR subproject will provide visibility into voltage levels at customers' premises, thus enabling the Companies to make adjustments at distribution transformers to lower voltage levels. Lower voltages will decrease customer consumption without the customer having to make adjustments to their energy usage. This decrease in customer consumption will reduce the amount of fuel needed to meet customer demand.

a. CVR Deployment Schedule

The CVR subproject will deploy CVR on O‘ahu, Maui and Hawai‘i Island. Based on information from the Electric Power Research Institute (EPRI), not every distribution circuit is suitable for CVR, as it is more effective if deployed on shorter, more heavily-loaded circuits. The Companies have done an initial evaluation of their distribution circuits and based on the lesson learnt from the Initial Phase, the plan is to enable CVR on 45% (176) of O‘ahu distribution circuits, 66% (60) of Maui distribution circuits and 70% (95) of Hawai‘i Island distribution circuits as part of the SGF Project. The Companies do not plan to deploy CVR on Lana‘i or Moloka‘i because the loads on those islands are smaller than the average loads required on distribution circuits for CVR to function cost-effectively.

As shown in Figure 5 below, the CVR subproject is scheduled to begin in January 2017 on O‘ahu, and early 2018 on Maui and Hawai‘i Island, with components becoming activated in late 2018 through the end of the SGF Project implementation. CVR deployment is dependent on when meters are installed and the supervisory control and data acquisition (“SCADA”) upgrades at substations are completed.

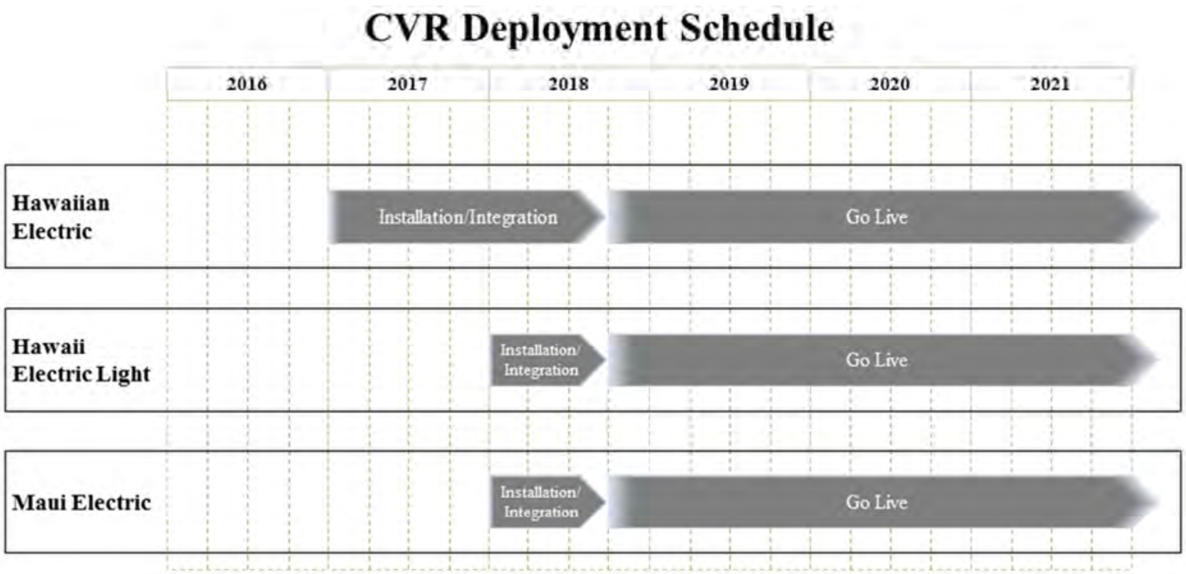

Figure 5

b. ***CVR Costs***

The total nominal cost for the CVR subproject is approximately $26.0 million, as shown in Table 20, below:

CVR Subproject Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Equipment	116	290	179	488	985	2,059
Hardware	71	-	-	-	-	71
Internal Labor	3,034	5,092	2,739	1,432	1,891	14,190[24]
Maintenance	302	603	728	776	786	3,195
Misc.	38	19	15	15	15	101
Outside Services	1,264	2,005	539	505	545	4,858
Software	864	695	-	-	-	1,559
Total	**5,690**	**8,705**	**4,200**	**3,215**	**4,223**	**26,033**

Table 20

Details for each cost category are provided below.

i. CVR Equipment

The estimated $2.1 million of equipment costs for the CVR subproject includes costs for: (1) capacitors; (2) pole replacement as a result of pole loading with capacitors installed; and (3) equipment required to upgrade existing [redacted] load tap changing equipment. Capacitors may be required on longer distribution circuits and/or circuits that support heavier motor loads. Not all circuits will require capacitors. It is estimated that approximately 5% of the Companies' circuits will require capacitor banks, and three capacitor banks will be required for each of the affected circuits.

It is anticipated that the incremental weight of the capacitor banks will require pole replacements in order to ensure proper pole loading and compliance with NESC specifications. The number of pole replacements is estimated according to the number of capacitor banks required.

Implementing CVR will require the Companies to be able to control the load tap changer of a transformer in order to lower the voltage on a circuit. This is done centrally via the [redacted] product. [redacted] is a type of load tap changer that the [redacted] product has already integrated with on O'ahu for use during the Initial Phase. The Companies plan to upgrade the load tap changers for the distribution circuits that are selected for CVR as part of the SGF Project. The costs of these CVR subproject equipment items are shown in Table 21, below:

[24] Includes $1,909,000 of incremental costs of internal labor resources, which are currently included in base rates as expense, and which have been reclassified as capital or deferred costs and included as a benefits offset for purposes of surcharge recovery under the Modified REIP Framework, as explained in Section IV.C.6 below.

CVR Subproject Equipment Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Capacitor Bank	-	-	-	255	519	773
Pole Replacements	-	-	-	233	466	700
[redacted] Upgrade	116	290	179	-	-	586
Total	**116**	**290**	**179**	**488**	**985**	**2,059**

Table 21

ii. CVR Hardware

As shown in Table 22 below, the hardware costs for the CVR subproject are estimated at approximately $71,000. These hardware costs are anticipated to be incurred in 2017, and consist of costs for: (1) [redacted] server; (2) [redacted] appliance. In the context of the CVR subproject, [redacted] is a [redacted] interfacing device that adds control logic to process and pass data between [redacted] and load tap changers over SCADA.

In the case of the [redacted] server, the primary production server was already acquired during the Initial Phase. The costs included in the CVR subproject are for an additional server that is needed to build the development/test environments. Having separate development/test and production servers is a standard implementation practice for all software systems at the Companies.

One [redacted] has already been purchased and implemented in connection with the Initial Phase. The CVR subproject hardware cost estimate includes costs for two additional [redacted] One of the additional [redacted] will be used as a production "hot spare" that will serve as a failover system should the existing [redacted] fail. The second additional [redacted] will be used as the development/test environment in support of programmatic changes and upgrades needed to manage and maintain the system.

CVR Subproject Hardware Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
[redacted]						
Total	**71**	**-**	**-**	**-**	**-**	**71**

Table 22

iii. CVR Internal Labor

The largest category of CVR subproject costs is for internal labor, estimated at approximately $14.2 million (or 143,000 hours). As summarized in Table 23, below, this includes costs for the Companies' personnel to: (1) design and install CVR hardware (including project management and preliminary engineering); (2) validate and troubleshoot voltage situations once the smart meters are installed; and (3) integrate CVR information into the EDW; as well as (4) allocated PMO costs.

The installation and preliminary engineering activities consist of costs to design and implement the additional [redacted] servers, [redacted] and [redacted] devices. Voltage validation support will occur as the smart meters are installed and provide the ability to read voltages at customers' premises. The Companies will use these voltage reads to validate, troubleshoot and correct issues on the circuits in order to keep them within tariff requirements. Internal labor will also be required to integrate the EDW to the [redacted] server to ensure that the CVR information is being made available for analysis via the EDW.

CVR Subproject Internal Labor Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Installation & Preliminary Engineering	2,821	4,785	2,554	1,253	1,670	13,083
Voltage Validation Support	113	158	98	46	47	463
EDW Integration	-	13	-	-	-	13
PMO	100	136	87	133	175	631
Total	**3,034**	**5,092**	**2,739**	**1,432**	**1,891**	**14,190**

Table 23

iv. CVR Maintenance

As shown in Table 24 below, the estimated maintenance cost for the CVR subproject of approximately $3.2 million consists of costs for SSNI Sensor IQ SaaS and [redacted] software maintenance. Sensor IQ provides near-real-time consolidation of voltage information from smart meters. This data is used for voltage analysis. The [redacted] software maintenance is for upgrades to the [redacted] appliances discussed above.

CVR Subproject Maintenance Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
[redacted]						
Total	**300**	**598**	**728**	**776**	**786**	**3,188**

Table 24

v. CVR Outside Services

The outside services costs for the CVR subproject are estimated at approximately $4.9 million, as shown in Table 25, below. This estimate includes consulting costs from Siemens to integrate the [redacted] servers into the respective SCADA systems (including preliminary engineering). In addition, the estimate includes costs for vendor services from the selected EDW vendor to integrate CVR data from the [redacted] product to the EDW for collection of CVR information. This is also integrated with data from the existing systems (e.g., TREX, AccuWeather) in order to populate the EDW.

CVR Subproject Outside Services Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
[redacted]						
PMO	54	74	47	77	19	271
Total	**1,264**	**2,005**	**539**	**505**	**545**	**4,858**

Table 25

vi. CVR Software

There are approximately [redacted] of estimated costs for [redacted] software licensing. This includes the perpetual server license fee of [redacted] and an associated per smart meter license fee of [redacted] As indicated above, not all of the smart meters installed in connection with the SGF Project will be added for CVR because CVR is not suitable for certain distribution circuits. As a result, there are no per smart meter license fees associated with the smart meters to be installed on Moloka‘i and Lana‘i.

4. Direct Load Control

The Companies’ existing EnergyScout program offers a $3/month rebate to residential customers in exchange for allowing the Companies the right to turn off a customer’s electric water heater for approximately one to four hours at a time, when needed, to help curb load demand. This DLC program was designed to help system operations during peak electricity usage periods to balance the system frequency during the loss of a generator, or during generation capacity shortfall situations. Turning off a water heater during these emergency periods allows the system operator to operate the grid in a safe manner during emergency situations, and in some cases, can help the system avoid rolling blackouts.

The DLC subproject will replace the existing end-of-life, one-way DLC switches with two-way DLC switches communicating via the AMI network provided by SSNI. The new switches will provide greater two-way information flow which will facilitate better monitoring and performance of the EnergyScout program,[25] while simultaneously leveraging the SSNI network for multi-purpose uses beyond AMI. The Companies are only proposing to do this for the customers on the existing EnergyScout program, and do not plan to expand the DLC implementation to new customers, in accordance with the Commission's directive on page 21 of its *Decision and Order* filed on December 29, 2009 in Docket No. 2009-0097.

Migration of the EnergyScout program into the new DR program portfolio is contemplated within the Integrated Demand Response Portfolio Plan ("IDRPP"). Currently there are two DR related dockets in progress: (1) the DRMS application in Docket No. 2015-0411; and (2) the DR Portfolio in Docket No. 2015-0412. DLC is included in the SGF Project for purposes of testing and leveraging the SSNI network. The Companies tested and installed 162 DLC switches as part of the Initial Phase.

a. ***DLC Deployment Schedule***

The DLC subproject involves the replacement of 32,000 existing water heating switches on a one-way communications system with new DLC switches that have two-way communications capability over the AMI network. Prior to the replacement of these switches, work will be done in 2017 and 2018 to integrate the existing Initial Phase two-way switches with the ESB and EDW. This will help prepare the ESB and EDW to accept data from the new switches deployed in 2020 and 2021.

As shown in Figure 6 below, 16,000 of 32,000 replacements will occur in each of the years 2020 and 2021. Equipment purchases for the installation will occur at least a quarter ahead of time. The switch replacements are only planned for existing O'ahu DLC customers since the EnergyScout program is not offered by Maui Electric or Hawai'i Electric Light. There are no plans for expansion to additional customers on O'ahu during the SGF Project. The existing one-way DLC switches are approximately in the eleventh year of their 15-year asset life (which is why the replacement is proposed to occurs after 2019). The costs of the new two-way switches have been included as part of the SGF Project, as their replacement will coincide with the implementation of the AMI network on which they will communicate.[26]

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[25] In 2005, Hawaiian Electric provided customers the option to enroll in two different EnergyScout programs (i.e., water heater and air conditioning) aimed at providing the Companies options for load curtailment and control, when necessary, to better manage the grid. In 2008, the program was considered mature with more than 30,000 participants.

[26] The existing one-way switches from Eaton/Cooper are estimated to have a 12 to 15 year asset life. The majority of all switches currently installed will be at or beyond the 15 year asset life in 2020.

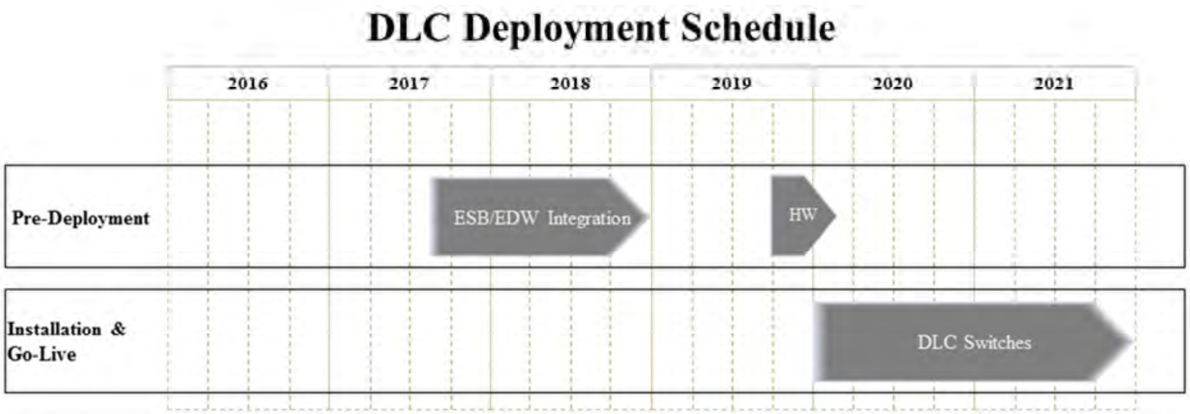

Figure 6

b. *DLC Costs*

The total five-year nominal cost for the DLC subproject is approximately $19.4 million, as summarized in Table 26 below, and includes costs specific to equipment, internal labor, maintenance, miscellaneous expenses and outside services.

DLC Subproject Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Equipment	[redacted]					
Internal Labor	12	6	4	532	509	1,063[27]
Maintenance	[redacted]					
Misc.	-	-	-	21	17	37
Outside Services	[redacted]					
Total	**525**	**386**	**213**	**9,477**	**8,818**	**19,419**

Table 26

i. *DLC Equipment*

The DLC equipment cost category consists of approximately [redacted] in costs for the 32,000 Eaton/Cooper water heating switches. Purchasing of these switches will begin in late 2019 with their subsequent deployment occurring in 2020 and 2021 after the residential AMI installation has been completed.

ii. *DLC Internal Labor*

The internal labor costs for the DLC subproject, estimated at approximately $1.1 million (or 11,000 hours), are for the management and execution of installing the DLC switches at

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[27] Includes $210,000 of incremental costs for internal labor resources, which are currently included in base rates as expense, and which have been reclassified as capital or deferred costs and included as a benefits offset for purposes of surcharge recovery under the Modified REIP Framework, as explained in Section IV.C.6 below.

customer premises, and to ensure the switches that are installed in the field go into an "active" state, which means they are communicating on the AMI network and can be controlled as needed. The cost estimate also includes some internal labor for integrating the switches with the EDW, as well as allocated PMO costs. The EDW costs are to facilitate the consolidation and sharing of DLC data for use across other operational, economic and customer data for analysis. Table 27 below provides these internal labor costs for the DLC subproject, by year, throughout the SGF Project.

DLC Subproject Internal Labor Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Installation & Validation	-	-	-	150	155	305
EDW Integration	4	-	-	-	-	4
PMO	8	6	4	382	354	754
Total	**12**	**6**	**4**	**532**	**509**	**1,063**

Table 27

iii. DLC Maintenance

The DLC subproject maintenance cost is estimated to be approximately [redacted] and includes costs for: (1) SaaS of the SSNI Home Area Network Communications Manager ("HCM") for 32,000 switches, to enable remote DLC and monitoring of the switches via the AMI network; (2) the SSNI DLC NIC card firmware upgrades; and (3) the SSNI DLC configuration software maintenance.

DLC Subproject Maintenance Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
HCM	[redacted]					
NIC Firmware						
Configuration SW						
Total						

Table 28

As shown in Table 28 above, the majority of the DLC maintenance costs are for SSNI's SaaS HCM fees. The fees are assessed on a monthly basis and tiered based on the total number of end point units connected. The bottom tier under SNNI's pricing applies to end points ranging from [redacted], which equates to a per unit fee of [redacted] In 2020, 16,000 end points will be added with a total annual fee of [redacted] In 2021, the remaining 16,000 end points will be added with a total annual fee of [redacted] The DLC maintenance costs presented in Table AC above, reflect the fact that the annual average number of units for purposes of monthly SaaS fees in 2020 and 2021 will be 8,000 and 24,000 respectively, with 16,000 units being transitioned out of project costs and into ongoing costs at the end of 2020.

iv. DLC Outside Services

The approximately [redacted] in outside services costs for the DLC subproject are comprised of costs for the contracting resources required to install the DLC switches at customers' premises, SSNI services to support the installation, project management and ESB and EDW integration, as shown in Table 29, below.

DLC Subproject Outside Services Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
[redacted]						
Total	[redacted]					

Table 29

The Companies plan to hire a contractor to remove the older DLC switches and install the new two-way communicating water heating switches. Along with the installation, the contractor needs to ensure that the switches are safely installed and confirm initial communication with the AMI network. The EDW and ESB external vendor costs include external vendor labor for project management, system design and requirements use case development, infrastructure installation, software development and testing (i.e., unit, integration, system, regression, user acceptance, performance and stress) required to implement the ESB and EDW portions needed to connect to and house the DLC information.

5. Enterprise Data Warehouse

The EDW subproject involves the enhancement and installation of an enterprise data platform that enables the Companies to process, store and analyze high volumes of data in near-real-time. This subproject will enhance and extend the Companies' existing data warehousing capabilities by connecting different and disparate data into a cohesive enterprise data model that will allow for cross-functional data analysis (e.g., customer, economic, operational) specific to the increased granularity of Smart Grid data needing to be collected and analyzed. This includes data warehousing infrastructure hosted in a SaaS environment, use case analysis to configure and develop the enterprise data model, integration of data from existing and new systems and the implementation of the tools needed to manage, maintain, support and conduct Smart Grid data analysis. For the EDW subproject, the Companies issued a RFP and selected Hitachi as the primary system integrator who will implement the EDW.[28]

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[28] See Exhibit E, Attachment 6 to the accompanying Application.

a. ***EDW Deployment Schedule***

The EDW deployment is scheduled over the five-year period with the main infrastructure, use case development and enterprise data model development to be completed in the first year. Each corresponding year's activities are then timed with each respective subproject release in order to collect and structure the data from the various newly implemented solutions.

b. ***EDW Costs***

The total estimated cost for the EDW subproject is approximately $10.0 million, as shown in Table 30 below, with a majority of the costs attributed to labor (internal and external) and software maintenance.

EDW Subproject Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Internal Labor	168	168	240	660	783	2,019[29]
Maintenance	[redacted]					
Misc.	19	8	8	11	11	56
Outside Services	[redacted]					
Total	**2,160**	**1,681**	**1,759**	**2,215**	**2,177**	**9,992**

Table 30

i. ***EDW Internal Labor***

The total internal labor costs for the EDW subproject are estimated at approximately $2.0 million (or 28,000 hours). As shown in Table 31, below, the EDW subproject will utilize internal labor to manage the implementation of the EDW and to perform some of the integration work between the EDW and other systems. Costs for additional integration work between the EDW and the AMI, CFS, CVR, DLC, MDMS and OMS subprojects are also included in the respective internal labor cost estimates for those subprojects because the costs reflected under EDW are for the work relative to the EDW platform, while the costs reflected under the other subprojects are for the work relative to those respective solutions.

EDW Subproject Internal Labor Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Systems Integration	133	143	206	574	697	1,755
PMO	34	25	34	86	85	264
Total	**168**	**168**	**240**	**660**	**783**	**2,019**

Table 31

[29] Includes $71,000 of incremental costs of internal labor resources, which are currently included in base rates as expense, and which have been reclassified as capital or deferred costs and included as a benefits offset for purposes of surcharge recovery under the Modified REIP Framework, as explained in Section IV.C.6 below.

ii. EDW Maintenance

The maintenance costs of the EDW subproject include an estimated total of [redacted] for the C3 IoT (formerly C3 Energy) SaaS solution selected as part of the Hitachi proposal to expand and enhance the Companies' EDW capabilities over the duration of the SGF Project, beginning in 2017 and completing in 2021.[30]

iii. EDW Outside Services

As shown in Table 32 below, the estimated outside services costs of [redacted] for the EDW subproject include costs for the primary system integrator, Hitachi (includes C3 IoT and Referentia) to develop, configure, integrate and load data into the EDW. Similar to the EDW internal labor costs, outside services costs for additional integration work between the EDW and the AMI, CFS, CVR, DLC, MDMS and OMS subprojects are also included in the respective outside services cost estimates for those subprojects because the costs reflected under EDW are for the work relative to the EDW platform, while the costs reflected under the other subprojects are for the work relative to those respective solutions.

EDW Subproject Outside Services Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
[redacted]						
Total	[redacted]					

Table 32

6. Enterprise Service Bus

The ESB subproject is needed to enhance and grow the use of the Companies' existing IBM WebSphere software which is used to monitor, control and translate data from one system to another. In the case of Smart Grid, this type of solution will allow for the automated interchange and flow of increased levels of Smart Grid data, such as that collected from the smart meters or circuits, to be shared across the Companies' various systems (e.g., DRMS, OMS, MDMS) while maintaining data quality and security.

The Companies issued an RFP for the ESB subproject, and selected Cognizant as the ESB system integrator.[31] Cognizant will extend and enhance the existing IBM WebSphere ESB used to support the SGF Project. This subproject includes the installation of new hardware and software, and system integration services. Cognizant will also assist the Companies in building effective, productive and cost-efficient Service Oriented Architecture ("SOA") capabilities that will add greater flexibility for data integration.

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[30] See Exhibit E, Attachment 6 to the accompanying Application.
[31] See Exhibit E, Attachment 5 to the accompanying Application.

a. ***ESB Deployment Schedule***

The implementation of Cognizant's ESB solution will span the entire duration of the SGF Project, beginning in early 2017 and ending in late 2021. The solution upgrades and enhancements will be conducted in the first year of the implementation. This includes building out the needed production and non-production environments, setting up and configuring the new enhanced modules and creating the company-specific SOA policies and procedures. Each corresponding years' activities are then timed with each respective subproject release in order to automate the integration of data through the ESB and the various new and existing systems.

b. ***ESB Costs***

The total nominal cost for the ESB subproject is estimated at approximately $10.3 million, as summarized in Table 33 below, and includes costs for hardware, internal labor, maintenance, miscellaneous items, outside services and software.

ESB Subproject Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Hardware	[redacted]					
Internal Labor	257	170	182	218	830	1,657[32]
Maintenance	[redacted]					
Misc.	20	8	8	10	11	56
Outside Services	[redacted]					
Software						
Total	**3,979**	**1,020**	**1,421**	**1,511**	**2,026**	**10,321**

Table 33

i. ***ESB Hardware***

New hardware will need to be installed as part of the ESB subproject in order to extend and enhance the existing IBM Websphere solution. The hardware will be centralized at Hawaiian Electric on O'ahu with extensions to Maui Electric and Hawai'i Electric Light. The estimated cost for this new hardware is approximately [redacted] and will be incurred during the first year of the ESB subproject deployment.

ii. ***ESB Internal Labor***

As shown in Table 34, below, it is estimated that approximately $1.7 million (or 25,000 hours) of internal labor will be used to manage the ESB subproject and to perform the integration

[32] Includes $66,000 of incremental costs of internal labor resources, which are currently included in base rates as expense, and which have been reclassified as capital or deferred costs and included as a benefits offset for purposes of surcharge recovery under the Modified REIP Framework, as explained in Section IV.C.6 below.

work between the ESB and other systems. This work will be done in tandem with Cognizant to assist in this integration process, as described in the ESB outside services section below.

ESB Internal Labor Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Systems Integration	195	150	154	159	751	1,409
PMO	63	20	27	59	79	248
Total	**257**	**170**	**182**	**218**	**830**	**1,657**

Table 34

iii. ESB Maintenance

The maintenance costs for the ESB subproject implementation include IBM software maintenance fees for the centralized ESB software from 2018 through 2021, at a total cost of approximately [redacted]. This maintenance fee is required in order to attain product vendor support of the licensed IBM software throughout the implementation.

iv. ESB Outside Services

The outside services cost estimate of approximately [redacted] for the ESB subproject includes costs for Cognizant to perform and manage the deliverables set forth in the ESB RFP. The estimate also includes additional consultant costs to perform the integration, as shown in Table 35, below:

ESB Subproject Outside Services Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Systems Integration	[redacted]					
PMO						
Total						

Table 35

v. ESB Software

Incremental software licensing fees for the ESB subproject will be incurred at the start of the ESB subproject, anticipated in early 2017. The license fees are for the IBM Websphere solution and are estimated at a total of approximately [redacted]

7. Meter Data Management System

The functions of the MDMS to be implemented during the SGF Project include: (1) collection of meter data; (2) validation, estimation and editing; (3) versioned meter data storage; (4) billing/usage calculation and aggregation; and (5) application interfaces and data integration. The primary purpose of this system is to manage the large volume of interval data collected from smart meters for billing purposes. The Companies issued an RFP for the MDMS and received several proposals that were evaluated based on functionality, technical aspects, price and vendor experience. Based on the responses, the Companies selected Omnetric Group ("Omnetric") as the MDMS system integrator.[33] The MDMS will be centralized at Hawaiian Electric on O'ahu and will serve all three Companies collectively.

a. MDMS Deployment Schedule

The MDMS subproject will be deployed in two phases. The first phase will utilize the new MDMS system to obtain and bill from register reads derived from the newly installed AMI infrastructure (includes smart meters, APs and relays). The Companies will install new hardware and implement the software product. This includes configuration of the product, as well as connecting the product to the Companies' CIS and SSNI's head end. The Companies will configure and build the MDMS software to obtain the register reads over the air via the SSNI product and then validate the data. The MDMS will also provide monthly register read billing determinants to the CIS.

The first phase of the MDMS subproject also includes integration work from the ESB, as well as populating the new EDW with the MDMS data. In addition, the CIS will be modified significantly to obtain readings and billing determinant data from the MDMS. The MDMS subproject will follow the SAP system development lifecycle (i.e., project preparation, blueprinting, realization, final preparation, go-live and post-go-live). The overall deployment of the first MDMS phase will take approximately 58 weeks, with an anticipated commencement in early 2017 and completion in early 2018, and will be followed by a 12-week stabilization period to ensure that the MDMS system is functioning properly and to work out any system issues prior to utilizing it for automated customer billing.

The second phase of the MDMS subproject will continue to use the MDMS system to obtain interval data reads from the smart meters, but will also validate and provide billing determinants to be used to calculate customer bills. This phase will also implement automation to remotely connect or disconnect services as related to move in/move out and credit connect/disconnect processes. This phase further includes incremental integration work between the MDMS, and the ESB and EDW solutions in support of the newly enabled functions. The CIS will be upgraded so that it can process interval data readings and correspondingly automate the handling of move in/move out and credit connect/disconnect processes. The overall deployment of the second MDMS phase will take approximately 60 weeks, with an anticipated commencement in spring 2018 and completion in mid-2019, followed again by a 12-week stabilization period.

Figure 7 below depicts the phases of the MDMS implementation.

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[33] See Exhibit E, Attachment 3 to the accompanying Application.

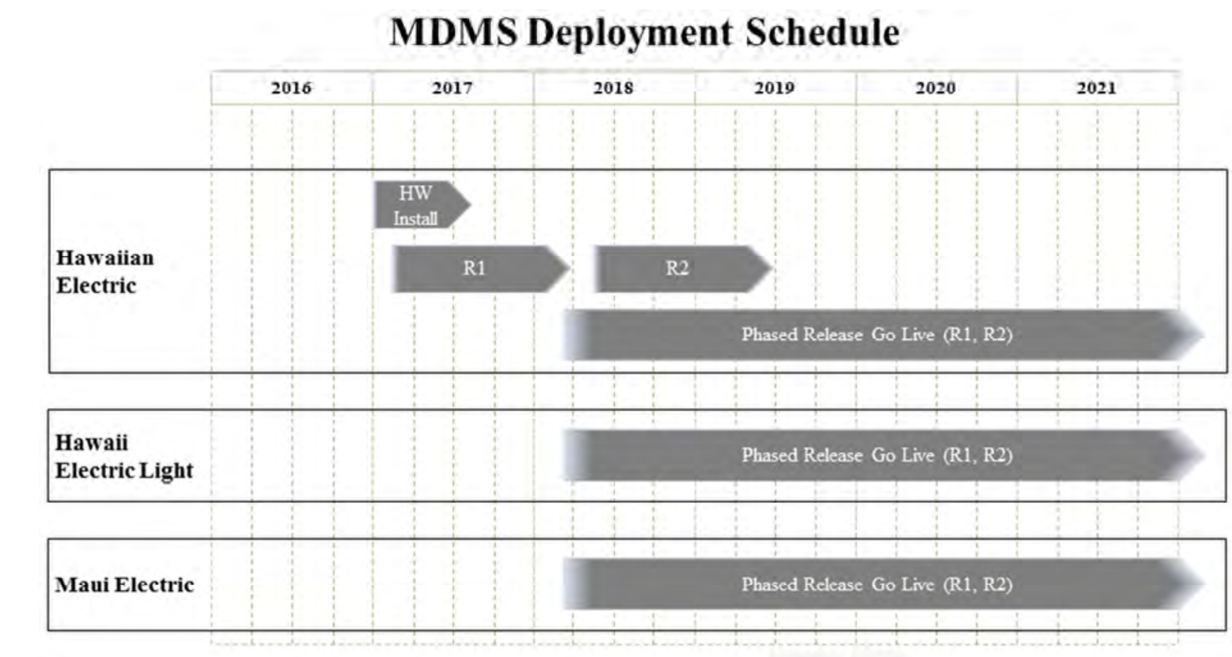

Figure 7

b. *MDMS Costs*

The total nominal cost for the MDMS subproject is estimated at approximately $47.9 million, as summarized in Table 36 below. This estimate includes costs for hardware, internal labor, maintenance, miscellaneous items, outside services and software.

MDMS Subproject Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Hardware	1,450	116	-	-	-	1,565
Internal Labor	1,555	2,282	1,930	-	-	5,766[34]
Maintenance	[redacted]					
Misc.	245	148	147	-	-	539
Outside Services	12,167	13,039	8,262	-	-	33,468
Software	[redacted]					
Total	**20,004**	**16,573**	**11,337**	**-**	**-**	**47,913**

Table 36

[34] Includes $285,000 of incremental costs of internal labor resources, which are currently included in base rates as expense, and which have been reclassified as capital or deferred costs and included as a benefits offset for purposes of surcharge recovery under the Modified REIP Framework, as explained in Section IV.C.6 below.

i. MDMS Hardware

The hardware costs for the MDMS subproject are associated with the needed servers, and have an estimated total of approximately $1.9 million, which will be incurred in the first two years of the SGF Project. The Companies have worked with Omnetric to develop the general specifications for the MDMS hardware pursuant to the Companies' standards.

ii. MDMS Internal Labor

Internal labor for the MDMS subproject is estimated at approximately $5.8 million (or 83,000 hours) and will be used to manage the project and perform the system integration work estimated for this subproject. Table 37 below provides a breakdown of the internal labor costs for the MDMS subproject.

MDMS Subproject Internal Labor Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Management, Development, Integration, Testing	1,230	1,523	878	-	-	3,631
Training, Stabilization	-	509	828	-	-	1,337
Server Installation	17	-	-	-	-	17
PMO	307	250	224	-	-	781
Total	**1,554**	**2,282**	**1,930**	**-**	**-**	**5,766**

Table 37

iii. MDMS Maintenance

The estimated maintenance costs for the MDMS subproject include costs for the software maintenance of the MDMS product solution (i.e., Siemens eMeter) over the five-year implementation of the SGF Project, at a total cost of approximately [redacted]

iv. MDMS Outside Services

As shown in Table 38 below, the outside services cost estimate of approximately $33.5 million for the MDMS subproject includes costs for Omnetric to configure the MDMS software per the requirements in the MDMS RFP. The estimate also includes additional consultant costs to perform the integration. All of the MDMS subproject outside services costs will be incurred during the first three years of the SGF Project, as the MDMS will go live beginning in 2020, with any additional integration or validation processes being handled by internal resources, as shown in Table 37 above.

MDMS Subproject Outside Services Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Management, Development, Integration, Testing	11,672	12,379	7,601	-	-	31,652
Training, Stabilization	-	507	527	-	-	1,034
Server Installation	306	-	-	-	-	306
PMO	188	153	135	-	-	477
Total	**12,166**	**13,039**	**8,263**	**-**	**-**	**33,468**

Table 38

v. MDMS Software

The estimated software costs of the MDMS subproject are for MDMS product licensing fees (per the MDMS RFP), and total approximately [redacted]. These costs are projected to be incurred in the first year of the SGF Project.

8. Outage Management System

An OMS is a computer system used by operators of electric distribution systems to assist in the restoration of power in the event of an outage. The OMS subproject will expand and enhance the existing OMS, which is currently in use at Hawaiian Electric on O‘ahu, to Maui Electric and Hawai‘i Electric Light, leveraging the Companies' existing OMS and adding additional capabilities that will capture information from the new smart meters over the AMI network to monitor, identify and inform system operators of outages on the respective distribution systems.

The Companies currently have no direct visibility into the status of electricity at a customer's premises, and therefore, rely on customers to call the Companies in the event of an outage. The AMI network will not only enable the Companies to read smart meters remotely, but also provide the ability to detect outages automatically without customers' help. In the event of an outage at a customer's premises, the smart meter will be configured to send a "last gasp" message to inform the Companies' system operators of the outage. This will reduce the duration of service interruptions and increase the efficiency of the Companies' outage responses and power restoration.[35]

[35] During the Initial Phase, the Companies decreased truck rolls by performing remote connect/disconnect capabilities of the approximately five thousand smart meters installed. This resulted in 496 remote disconnects, 422 remote reconnects to date since May 2014. Additionally, approximately 1,023 check reads and Encoder Receiver Transmitter (ERT) reads from 212 meters (remote meter reading and meter pinging) also resulted in a decrease in second reads (car rolls).

The Companies deployed an OMS on O‘ahu in the 2008-2009 timeframe with the purpose of receiving and grouping customer outage calls so that dispatchers could determine the most likely cause of the outage. With the deployment of the SGF Project, the existing OMS will be enhanced to create a more capable ODS that leverages the new smart meter technology across the Companies' service territories.

With the enhanced and expanded OMS, the AMI "last gasp" messages will be fed into SSNI's ODS software,[36] which will perform various filtering of all "last gasp" messages to determine which messages are in regard to sustained outages and should be reported to the OMS (as opposed to transient events where power will be returned to the customer momentarily). Integration will be required between SSNI's ODS to the Companies' OMS and CIS to generate the trouble tickets that feed into the OMS.

This expanded and enhanced OMS will assist Maui Electric and Hawai‘i Electric Light in their outage restoration efforts, as currently they still rely on an offline database system where they manually print trouble tickets to sort and respond to outages. The enhanced and expanded OMS will also enable the Companies to "ping" smart meters to determine if the smart meters have power, which will assist in the restoration process, especially during larger, geographically widespread outages.

a. ***OMS Deployment Schedule***

The OMS subproject is scheduled to be implemented in a single rollout between mid-2018 and early fall 2019, followed by a 12-week stabilization and validation period. As shown in Figure 8 below, this deployment will begin with a data capture and cleansing period followed by the single-phase deployment.

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[36] Hawaiian Electric currently uses SSNI's ODS system that utilizes AMI data to analyze outages across O‘ahu. This service will be enhanced with the additional integration solutions (i.e., EDW and ESB) provided by the SGF Project, and will be expanded to Hawai‘i Electric Light and Maui Electric as part of the OMS subproject.

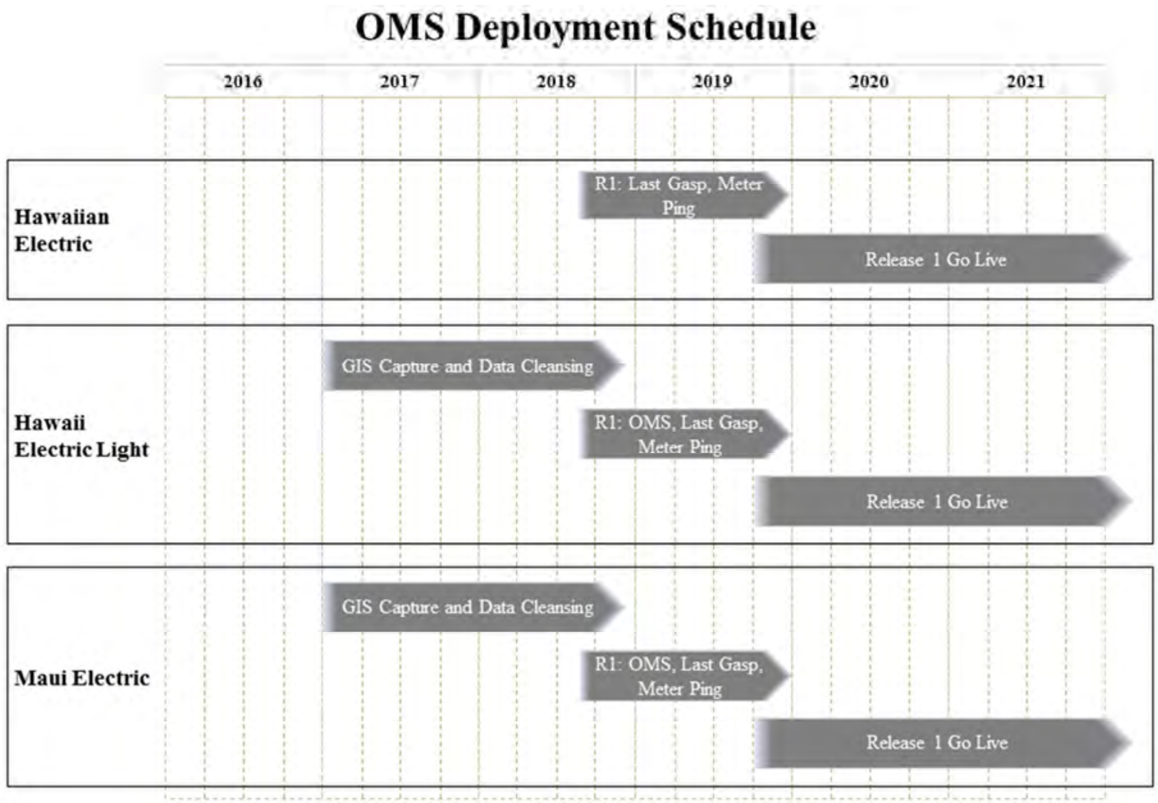

Figure 8

b. ***OMS Costs***

The total nominal cost for the OMS subproject is estimated at approximately $17.4 million, as shown in Table 39, below. This estimate includes costs for internal labor, maintenance, miscellaneous items, outside services and software needed for the OMS deployment. The reason there are no hardware costs included in the estimate is that Maui Electric and Hawai‘i Electric Light will be leveraging Hawaiian Electric’s existing OMS hardware that is centralized on O‘ahu to enhance and expand the system.

OMS Subproject Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Internal Labor	41	530	2,163	-	-	2,733[37]
Maintenance	[redacted]					
Misc.	-	101	116	-	-	217
Outside Services	[redacted]					
Software	[redacted]					
Total	**2,385**	**5,937**	**9,104**	**-**	**-**	**17,426**

Table 39

[37] Includes $106,000 of incremental costs of internal labor resources, which are currently included in base rates as expense, and which have been reclassified as capital or deferred costs and included as a benefits offset for purposes of surcharge recovery under the Modified REIP Framework, as explained in Section IV.C.6 below.

i. OMS Internal Labor

Internal labor will be used to manage the expansion of the OMS to Maui Electric and Hawai'i Electric Light, and to perform the integration work between the OMS and other systems as needed. Since the OMS deployment is scheduled to be completed by 2020, the costs specific to its management will only be incurred during the first three years of the SGF Project. The resulting integration work that will be required to complete the validation process is scheduled beginning in 2018 and ending in 2021. The approximately $2.7 million (or 37,000 hours) of estimated internal labor for the OMS subproject are shown in Table 40 below:

OMS Subproject Internal Labor Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Management, Development, Integration, Testing	-	445	1,416	-	-	1,861
Training, Stabilization	-	-	573	-	-	573
PMO	41	85	173	-	-	299
Total	**41**	**530**	**2,162**	**-**	**-**	**2,733**

Table 40

ii. OMS Maintenance

The maintenance cost estimate of the OMS subproject includes costs for incremental Oracle OMS software maintenance fees for the duration of the subproject, beginning in 2018 through the end of the SGF Project, and is estimated at approximately [redacted].

iii. OMS Outside Services

As shown in Table 41 below, the outside services cost estimate for the OMS subproject includes costs for Oracle to expand and configure the existing OMS software.[38] The estimate also includes additional consultant costs to perform the integration. All outside services costs will be incurred between 2017 and 2019, during the period specific to the OMS subproject implementation. The remaining labor resources necessary for validation and software maintenance will be provided by internal staff, as depicted in Table 40 above.

[38] See Exhibit E, IV.A to the accompanying Application.

OMS Subproject Outside Services Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
GIS Data Capture	[redacted]					
Management, Development, Integration, Testing						
Training, Stabilization						
PMO						
Total						

Table 41

iv. OMS Software

The estimated software costs for the OMS subproject are for the incremental Oracle OMS software product licensing, which is scheduled to be incurred upon commencement of the OMS subproject in 2018, and total approximately [redacted] The licensing is to enable OMS for Maui Electric and Hawai'i Electric Light. Software licensing costs for the OMS on O'ahu are already included in Hawaiian Electric's existing base rates, and therefore are not included in the costs for the OMS subproject.

9. Customer Engagement

As detailed in Exhibit C, in order to be successful, the SGF Project will require a proactive, targeted, collaborative, responsive and flexible communications effort to educate and engage with customers. Consistent with the results of prior Smart Grid implementations at other utilities, the lessons learned from the Initial Phase revealed that engaging customers early and often provides customers with more opportunities to learn about the benefits of Smart Grid technologies and allows them to make more informed decisions. Toward that end, the eight activities that comprise the CE component include engaging customers through: (1) community outreach; (2) customer education; (3) government relations; (4) third-party engagement; (5) media relations; (6) customer research; (7) employee engagement; and (8) customer service support.[39]

a. CE Deployment Schedule

Since the deployment of smart meters involves visiting customers' premises, the majority of the CE component activities will be performed during the first three years of the SGF Project,

[39] The costs detailed herein are for the Companies' planned customer engagement during the SGF Project, and do not include any costs that were incurred in the Initial Phase. The Companies' customer engagement activities for the SGF Project include a combination of both work that is being done for the CFS, and the eight customer engagement activities listed above.

coincident with the smart meter deployment. However, certain additional customer engagement activities will also be carried out in the latter years of the SGF Project, in order to continue to interact with the public on the status of the SGF Project implementation.

b. *CE Costs*

The total nominal cost for the CE component is estimated at approximately $8.4 million, as shown in Table 42 below, and includes costs for internal labor, miscellaneous items and outside services, specific to customer education and information notifications and materials that will be provided through various media and print options.

CE Component Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Internal Labor	486	484	503	534	36	2,045
Misc.	31	19	20	19	1	90
Outside Services	2,110	1,392	1,193	720	862	6,277
Total	**2,628**	**1,896**	**1,716**	**1,273**	**899**	**8,412**

Table 42

i. *CE Internal Labor*

The internal labor cost estimate for the CE component is approximately $2.0 million (or 25,000 hours), as shown in Table 43 below. These costs are inclusive of the internal staff that will be working directly on the various planned customer engagement activities and events, as well as the overall project management required for the Companies to maintain a clear and consistent outreach and communications plan during the SGF Project. This is necessary in order to ensure that customers and stakeholders alike are staying well-informed as to the status of and available information pertinent to the various subprojects as they are deployed.

CE Component Internal Labor Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
Customer Outreach & Education	442	455	469	483	-	1,849
PMO	45	29	35	51	36	196
Total	**486**	**484**	**503**	**534**	**36**	**2,045**

Table 43

ii. *CE Outside Services*

The estimated cost of outside services for the CE component is approximately $6.3 million, as shown in Table 44 below. The estimate includes costs associated with developing communication pieces to notify the public about the SGF Project and educate customers about the benefits and tools available to them through the CFS and AMI, as well as costs for project management to oversee these various outreach tools.

CE Component Outside Services Implementation Costs by Year (Nominal $000s)						
Category	2017	2018	2019	2020	2021	Total
SGF Project Communications	2,086	1,377	1,175	690	858	6,185
PMO	24	16	19	30	4	92
Total	**2,110**	**1,392**	**1,193**	**720**	**862**	**6,277**

Table 44

10. Project Management Office

As discussed in Section I.B above, the PMO will provide services needed to manage and maintain the overall governance, coordination and facilitation of the overall SGF Project. The costs for these services are included in the cost sections above under the "PMO" line items. The services provided under the PMO consist of three major services:

- Project leadership and cross component management: This service will provide the overall leadership needed to manage, control, escalate and resolve key cross functional issues of the SGF Project. The project leadership team will execute the overall SGF Project governance and facilitate the executive and management steering groups. It is also responsible to provide facilitation and coordination with the Companies' existing governing structures for various business approvals (e.g., technical architecture coordination with the Information Technology Architecture Review Committee, project authorization and expenditure monitoring with the Project Review Committee);

- Project management administration support, control and reporting: This service will provide resources for the overall day-to-day management of the SGF Project's resources and is responsible for the project management processes as governed by the project's leadership. It also includes executing the SGF Project's procurement, accounting, regulatory and budgeting activities.

- Business integration: This service will address organizational change management which includes activities to review existing positions that will be impacted by the new solutions such that new job descriptions may be needed and/or existing jobs need to be retired. Activities to be performed include position description creation, organization position analysis, compensation analysis and other organizational change activities that prepare individuals for the change. This service will also address job training and knowledge transfer that includes activities to plan, create and document training-related activities targeted for trainers and end-users. It further includes activities to monitor and report on the knowledge transfer process required to ensure that the Companies' support staff are able to manage and maintain the new solutions beyond their implementation. Moreover, this service addresses the need to establish new business processes as well as improve existing business processes as the new Smart Grid solutions are introduced. These business process improvements will need to be coordinated across the various subprojects and into existing cross-functional business processes in order to be successful.

a. PMO Deployment Schedule

As shown in Table 45 below, the PMO will exist throughout the SGF Project for its full duration of five years. The cost of the PMO services will be at its highest in the first three years of deployment and will taper off towards the last two years as components of the SGF Project are completed.

PMO Services	2017	2018	2019	2020	2021
Project Leadership	4	4	4	4	3
Project Administration Support, Controls and Reporting	5	5	5	5	5
Organization Change Management and Process Improvements	3	3	3	2	2
Total FTEs by Year	**12**	**12**	**12**	**11**	**10**

Table 45

b. PMO Costs

The PMO costs are primarily derived from the costs of labor resources needed to execute the PMO roles throughout the project. The PMO services will be supported by approximately 12 FTEs throughout the SGF Project implementation. These resources will be a combination of existing and incremental internal resources assigned to the project, as well as outside service contractors needed to enhance the PMO and provide existing Smart Grid expertise to the SGF Project. These costs are already included in the other respective cost component estimates above. Attachment 1 provides further details on the PMO costs allocated by SGF Project component.

C. ONGOING COSTS NOT INCLUDED IN THE SGF PROJECT IMPLEMENTATION COST ESTIMATE

In addition to the $340 million of SGF Project costs discussed above, after the various components of the project are placed in service, the Companies anticipate that approximately $345 million in additional costs will need to be incurred in order to support and maintain the investment over its life of over twenty years. These ongoing expenses are related to:

(1) Operational support and maintenance, which includes the incremental internal labor needed to operate and manage the new systems (e.g., patch management, security updates, performance management, monitoring, analysis), the software maintenance fees needed to keep these system current and supported by the solution vendors, and the SaaS fees needed for continued use of such system services (see Attachment 2 of Exhibit G to the accompanying Application); and

(2) Lifecycle management, which includes the replacement of assets per their estimated useful life as further detailed in Attachment 6.

D. POST-IN-SERVICE COSTS RELATED TO EXISTING METERS

As discussed in Exhibit F to the accompanying Application, the Companies propose to recover the cost of their existing meters (i.e., the estimated $51 million net book value of the meters when they are replaced with smart meters) on a straight-line basis over ten years, and to include the unamortized amounts in rate base. As discussed in Section IV below, the economic analysis for the SGF Project takes into account the ten-year amortization of the proposed regulatory asset created in connection with the remaining book value of the Companies' existing non-AMI meters.

This post-in-service cost was calculated by beginning with the net book value of the existing non-smart meters at the end of 2015 of $54 million. The end of 2015 balance of $54 million was then adjusted downward by $3 million to reflect the overall five-year NSM tariff participation rate of 2% at Hawaiian Electric and 5% at each of Maui Electric and Hawai‘i Electric Light and the associated non-smart meter inventory needed to support customers who opt out via the tariff. The actual book value recognized at the time of deployment may vary based on the timing of the actual AMI-meter deployments.

III. SGF PROJECT BENEFITS

As discussed above, the Companies' strategy for developing and deploying Smart Grid uses a phased approach, recognizing that core infrastructure and basic functionality must be put in place first. The SGF Project represents the foundation to the Companies' full Smart Grid rollout. Although the full value of the SGF Project will not be realized until the implementation of future phases, there are a number of immediate monetary and non-quantified benefits that will inure directly and indirectly to customers when the various SGF Project components are placed in service.

The immediate benefits to customers of the SGF Project consist of quantified monetary and/or non-quantified benefits. The quantified monetary benefits are made up of: (1) "Operational Benefits" that are passed to customers by way of reduced revenue requirements; and (2) "Direct Customer Benefits" that inure directly to customers, such as through adjustments in their energy use patterns that reduce consumption, as well as through energy cost or other adjustment clause mechanisms, without any direct impact on revenue requirements. The third category of "Non-Quantified Benefits" represents benefits to customers that cannot be reasonably monetized at this time.

As further detailed below, the immediate SGF Project benefits that can be reasonably quantified at this time include benefits related to: (1) AMI (including benefits related to the MDMS, ESB and EDW); (2) CFS; (3) CVR; (4) OMS; and (5) DLC. The total nominal and present values of these benefits are approximately $877 million and $345 million, respectively.[40] In the near term, the monetary value of the Operational Benefits will serve to mitigate the economic impact of the SGF Project by virtue of being included as an offset to the SGF Project

[40] For purposes of this analysis, "nominal" refers to actual values in the years incurred, unadjusted for the time-value of money. "Present value" refers to future values that have been discounted to current dollars at the Companies' weighted average cost of capital.

costs included in the Renewable Energy Infrastructure Program ("REIP") REIP surcharge ("Surcharge").[41]

The quantified benefits of AMI, portions of OMS and the "Existing Internal Labor Offset" discussed below are Operational Benefits proposed for inclusion as an offset to the costs that are recovered through the Modified REIP Framework. The CFS, CVR and DLC benefits (as well as the remaining portions of the OMS benefit) are not included as offsets to surcharge recovery through the Modified REIP Framework, as these Direct Customer Benefits. The importance of the distinction between Operational Benefits and Direct Customer Benefits relates to the fact that the Modified REIP Framework requires that costs recovered through the REIP Surcharge be offset by the cost savings derived from the various subprojects. However, the Direct Customer Benefits are taken into account for purposes of evaluating the economic justification of the overall SGF Project as discussed in Section IV, below.

The Non-Quantified Benefits of the SGF Project include benefits to customers such as those related to customer satisfaction derived from improved customer experience or community benefits such as reduced greenhouse gas ("GHG") emissions. Though many these Non-Quantified Benefits are societal and intangible, part of the benefits realization process will still be to assess customer satisfaction and experience with the Companies' Smart Grid as a whole. This will be done through customer surveys and focus groups to continue to match customer tools to customer needs.

A. BENEFIT ESTIMATING METHODOLOGY

In evaluating the immediate benefits of the SGF Project, the Companies have linked each of the various benefits to one or more of the five Smart Grid strategic themes discussed in the Smart Grid Roadmap, namely: (1) Customer Empowerment; (2) Distributed Energy Resource ("DER") Integration; (3) Grid Efficiency, Reliability and Connectivity; (4) Safety and Workplace Efficiency; and (5) Innovation, Information and Connectivity.[42] This was done to ensure that the subprojects and the subsequent benefits that correlate with them are driven by the Companies' priority to provide more options to customers while working toward creating a more stable and efficient grid.

The Companies have utilized several baseline assumptions, similar to those presented in the costing assumptions in Section II.A above, in order to appropriately apply the correct costs to their related benefits. These assumptions are provided as Attachment 7 and have been applied throughout the benefits quantification process detailed herein, as necessary.

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[41] An electronic copy of the economic model used to evaluate the quantified SGF Project benefits will be provided in a separate transmittal.

[42] For purposes of quantifying benefits, the various impacted business areas used existing data to derive their current states and then applied the expected enhancements to those baselines to determine the future steady state. The expected improvements were derived from industry benchmarks, research of other utilities that have implemented Smart Grid and/or results of the Initial Phase. The differences between current states and future states provide the annual benefit potential assumed within the cost-benefit model.

B. SGF PROJECT NON-QUANTIFIED BENEFITS

In addition to the quantified benefits, the SGF Project will deliver certain benefits that cannot be reasonably quantified at this time. As discussed in the Smart Grid Roadmap, there are certain benefits (e.g., reduced GHG emissions, reduced dependency on foreign imported oil, increased renewable economic growth) that will be gained but cannot effectively be quantified. Certain benefits are considered to be intangible such as improved customer service. Other benefits such as increased distributed renewable energy cannot be quantified because the data to quantify them is currently missing and/or too expensive to attain for quantification. Regardless, these benefits are considered real and will help the State of Hawai‘i attain its 100% renewable energy goal.

For discussion purposes, the following is a general summary of potential non-quantified benefits that would be delivered as part of the SGF Project:

- Customer satisfaction improvements potentially driven by improved experiences with contact center specialists, more transparency or improved data in billing, better tools and options for customers to manage their energy consumption, improved outage restoration time, etc. – Although the Companies are able to measure customer satisfaction via survey tools, it is difficult to specifically attribute these types of benefits to a single project (i.e., the SGF Project). Moreover, even with key metrics to measure customer satisfaction, it is difficult to translate such metrics into actual monetary savings;

- Environmental benefits from reduced reliance on fossil fuels and increased usage of renewable energy sources – Improved and safer integration of renewable energy sources through the Smart Grid provides increased ability to utilize local renewable energy resources. With the availability of such local renewable resources, the dependency on foreign oil imports is reduced. Although this will contribute to local economic growth, it is not yet clear if such actions will generate immediate savings in the near term. Regardless, in the long term and for reasons related to State and national security, moving off of foreign imported oil is considered desirable, although not quantifiable in terms of savings that lower customer bills.

- Economic growth – Increased local renewable energy industry economic diversity and growth is possible due to the introduction of new technologies and capabilities that spawn new local businesses. This has already occurred with the increase in solar companies in the recent years. The SGF Project will also introduce new jobs (e.g., CVR analysts, AMI network engineers) related to the new technologies introduced. These new jobs will be offset by the retirement of old jobs (e.g., meter readers). It is anticipated that during the SGF Project the injection of its investment will help grow the local economy as the Companies look to optimize their related investments locally. It is however, difficult to specifically relate this benefit to just the SGF Project in its five-year timeframe, as there are other factors at play in the local economy at the same time.

- Reduced GHG emissions – A 1% reduction in power output from a fossil-fuel-fired plant results in an annual reduction of approximately 45,000 metric tons in carbon dioxide (CO_2) emissions.[43] For the SGF Project, as an example, it is estimated that approximately 16,380 MWh of energy per year could potentially be saved by engaging customers through the CFS to act upon options that will lower their energy usage. This translates to a reduction of approximately 12,047 metric tons of CO_2 emissions per year which can be translated into approximately $174,680 per year via the use of the GHG retail offset value as indicated on the Green Power Network.[44] This type of benefit quantification is normally only indicative and therefore, not included as a "hard" benefit that can translate into direct tangible savings. However, this type of benefit is tantamount to avoided costs that will occur in the future once the SGF Project is implemented.

Specific non-quantifiable or intangible benefits that directly pertain to the various SGF Project components are discussed in the subsections below.

C. SGF PROJECT QUANTIFIED BENEFITS

The Smart Grid platform enabled by the SGF Project will have an expected useful life of 20 years. As a result, the estimate of the immediately quantifiable benefits of the SGF Project is based on a 20-year project life (i.e., from 2017 to 2036). Table 46 below shows the value of those benefits on both nominal and present value terms discounted at the Companies' weighted average cost of capital.

SGF Project Quantified Benefits ($ Millions)		
	Nominal (Yrs. 1-20)	Present Value (Yrs. 1-20)
Advanced Metering Infrastructure	290	116
Customer Facing Solutions	150	54
Conservation Voltage Reduction	384	151
Direct Load Control	26	10
Outage Management System	17	7
Existing Internal Labor Offset	10	7
20-Year Total SGF Project Benefits	**877**	**345**

Source: "Ben Totals by Company" tab in Attachment 8

Table 46

[43] Based on the combined emissions from Hawaiian Electric, Maui Electric and Hawaiʻi Electric Light's major sources of GHG emissions for calendar year 2012, which is approximately 4.5 million metric tons of CO_2.

[44] This high level quantification of GHG emission reduction is based on 455,000 customer accounts, at 15% participation, and of those a 4% energy savings derived from an average energy usage of 6,000 kWh per year. The energy saving in kWh is then translated into potential metric tons of CO_2 emission reductions using the eGRID2012 data from the U.S. Environmental Protection Agency. The resulting reduction in CO_2 is then valued using the Green Power Market's Retail GHG Offset Products to generate the expected dollar saved per year. Available at https://www.epa.gov/energy/egrid and http://apps3.eere.energy.gov/greenpower/markets/carbon.shtml?page=0

1. Advanced Metering Infrastructure

As discussed in turn below, the quantified AMI-related benefits of the SGF Project arise from: (1) reduced labor and associated costs specific to monthly manual meter reads; (2) avoided costs associated with the purchase, installation and testing of non-AMI meters; (3) reduced overhead related customer service representatives who handle billing and service scheduling calls; (4) reduced costs specific to system operations; and (5) increased collection of non-paying customer costs. Collectively, these benefits have been estimated to be $290 million in nominal dollars, as shown in Table 47, below.

AMI Subproject Benefits (Nominal $000s)	
Benefit Area	Value
Reduced Meter and Field Services Costs	156
Avoided Meter Engineering Costs	57
Reduced CSR Staffing from Billing and Service Reconnect Calls	30
Improved System Operations	2
Increased Billing Accuracy and Accounts Receivable Collections	45
20-Year Total AMI Benefits	**290**

Source: "Ben Totals by Company" in Attachment 8

Table 47

a. Meter and Field Services

As a result of the ability to remotely read and connect/disconnect the smart meters, one of the business areas that will be most significantly impacted by AMI is the Meter and Field Services area. AMI will automate the majority of meter services that are currently conducted manually, including monthly meter reading, disconnection and reconnection of service, and supervision and support associated with these manual activities. The automation of these functions will also result in a corresponding reduction in the levels of meter reading vehicles and equipment. As shown in Table 48 below, these benefits will reduce Expense expense in the following areas:

Reduced Meter and Field Services Costs (Nominal $000s)	
Benefit Area	Value
Monthly Meter Reading Costs	90,424
Off-Cycle Meter Reading Costs	43,185
Meter Reading Staffing Overhead	13,523
Meter Reading Vehicle Leasing and Maintenance	7,188
Automatic Meter Reading ("AMR") Fees	537
Meter Reading Devices and Accessories	800
20-Year Total Meter and Field Services Benefits	**155,656**

Source: B.F.1, B.F.2, B.F.10, B.F.11, B.F.8, B.F.12 tabs in Attachment 8

Table 48

i. Monthly Meter Reading Costs

The Companies anticipate that with AMI there will no longer be a need for manual meter reads except in the rare cases where the smart meter is unable to communicate with the AMI Network (estimated to be 1% of total smart meters). Using the average number of minutes taken for on-cycle reads (6.4/8.6/10.9 minutes/read, Hawaiian Electric, Maui Electric and Hawai‘i Electric Light respectively), the number of smart meters unable to communicate with the AMI network (1% of total smart meters), and the average available hours per meter reader per month (142 hours/month), the number of meter readers required to service these non-communicating smart meters was calculated to be 7 FTEs.[45] Based on this requirement, the Companies estimate a reduction in 49 FTEs, an approximate 87% reduction which translates to approximately $90.4 million in savings.

ii. Off-Cycle Meter Reading Costs

Off-cycle meter reading refers to a situation where a customer requests a meter read to be validated or where the utility needs to connect or disconnect service. Currently, off-cycle meter reading needs to be performed manually by dispatching a field service representative to customers’ premises. The Companies anticipate that with AMI, that there will no longer be a need to manually perform these types of activities.

Similar to the calculation of the reduction in the number of meter readers, the Companies have calculated the reduction in off-cycle meter reads by beginning with the total number of off-cycle meter reads, connections and disconnections, which accounts for approximately 1.2% of the total number of meters on average. This was multiplied by the time required for each respective process to arrive at the total number of hours currently spent on off-cycle meter reading, connections and disconnections annually. The Companies then adjusted that number of hours to account for the non-communicating meters and NSM tariff participants discussed above. Based on these projections, the Companies estimate that the current number of field services representatives can be reduced by a total of 21 FTEs, a 64% reduction which translates to approximately $43.2 million in savings.

iii. Meter Reading Support Staff

As a result of the reductions in number of manual meter readers and field services personnel, there will also be a reduction in the number of supervisors and administrative staff who currently support these activities. Currently, these activities are supported by a total of 17 FTEs comprised of a director, six supervisors and ten administrative support positions. The number of supervisors and administrative staff will be reduced to five and five, respectively. The corresponding value of this reduction is estimated to be approximately $13.5 million.

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[45] The costs associated with the remaining manual meter reading for NSM Tariff participants have been excluded from the benefits quantified herein, as those costs would be recovered through the tariff program fees independent of the SGF Project and REIP Surcharge mechanism.

iv. Meter Reading Vehicle Leasing and Maintenance

The reduced number of truck rolls associated with the reduced number of manual meter reads, validations, connections and disconnections will result in a reduction in the number of service trucks that the Companies annually purchase and/or lease from approximately 80 per year to 40 per year. Taking into account a corresponding reduction in the costs for their garaging and maintenance cost, the value of this benefit is estimated to be approximately $7.2 million.

v. AMR Meter Reading Fees

The Companies currently perform a limited level of AMR meter reads for purposes of billing commercial clients and measuring independent power producer ("IPP") generation. The cost of these activities in 2013 was $63,000. It is anticipated that AMI will eliminate the need for AMR except in cases where: (1) a commercial customer enrolls in the NSM tariff program (estimated to be 1% of commercial customers); (2) a commercial customer has a non-communicating meter; and/or (3) AMI technology does not yet support certain billing functions needed for IPPs and/or coincident billing. The Companies estimate that the elimination of the majority of AMR costs enabled by AMI will result in a 37% annual cost reduction, with the resulting total benefit estimated at approximately $537,000.

vi. Meter Reading Devices and Accessories

Currently, manual meter readers and field services personnel are equipped with Itron hand-held devices necessary to read AMR meters. Based on 2012 actuals, the Companies estimate the replacement cost of these devices to be approximately $330,000 every eight years. Similar to the case with reduced service trucks, the Companies anticipate that the reduction in AMR meters will reduce the cost of replacing hand-held devices by 58%, a savings of approximately $800,000.

b. Meter Engineering

The Companies' current capital and expense budgets include costs associated with replacing aging non-smart meters with new non-smart meters, and related testing. The installation of new smart meters in connection with the SGF Project will largely eliminate the need to purchase, install and test non-smart meters, as shown in Table 49 below.

Avoided Meter Engineering Costs (Nominal $000s)	
Benefit Area	Value
Meter Purchases	34,554
Meter Installation Labor	21,577
Moratorium on ANSI Testing for Installations	290
Over-the-Air ("OTA") Programming & Testing Efficiency Increase	996
20-Year Total Meter Engineering Benefits	**57,418**

Source: B.E.1, B.E.10, B.E.4, B.E.2 in Attachment 8

Table 49

i. Meter Purchases

Based on the revenue requirements approved in the Companies' last respective rate cases, the Companies' total annual capital budget for non-smart meters is $1.4 million. After taking into account the anticipated 3% NSM tariff participation, 1% non-communicating meter projections and minimum meter inventory requirements, the Companies estimated that 93% of the budgeted existing non-AMI meters will be eliminated from the budget. As a result, the Companies anticipate a corresponding $1.3 million avoidance of annual investment in non-AMI meters, which results in a total avoided capital investment of approximately $34.6 million.

ii. Meter Installation Labor

Eliminating 93% of non-smart meters will also reduce the need for labor associated with installing non-smart meters. Currently, an estimated 74% of customers' meters are self-contained meters, and 26% are transformer-rated meters. It takes a Senior Meter Electrician approximately three-tenths of an hour to install or replace a self-contained meter, and 1.4 hours to install or replace a transformer-rated meter. Based on the estimated avoided costs for non-smart meter purchases discussed above, the Companies estimate the avoided labor cost associated with installing non-smart meters to be approximately $21.6 million.

iii. Moratorium on ANSI Testing for Installations

G.O. 7 requires that meters be tested when they are installed or removed. ANSI testing a meter (both smart meters and non-smart meters) takes a Senior Meter Electrician approximately two-tenths of an hour. The Companies are requesting a waiver of this requirement during the five-year duration of the SGF Project that would eliminate the need to test all meters (both smart meters and non-smart meters) between 2017 and 2021. The corresponding cost avoidance associated with the proposed waiver is approximately $290,000 over the implementation period.

iv. OTA Programming & Testing Efficiency Increase

An additional requirement of G.O. 7 requires that the Companies regularly maintain meters, through testing and/or programming, to ensure optimal performance. In 2013, the Companies tested and/or reprogrammed 9,857 meters. Pursuant to this provision, the Companies are required to test 2.02% of their meters every year. This testing is performed by either a Meter Technician (approximately 28% of the time) or Senior Meter Electrician (approximately 72% of the time). It takes a Meter Technician or Senior Meter Electrician approximately three-tenths of an hour to test and/or re-program a meter for the purposes of regular maintenance to ensure that the meters are functioning properly.

With AMI, it is expected that the amount of associated non-smart meter maintenance costs required by G.O. 7 will be eliminated due to the installation and replacement of older meters with the new standard smart or non-smart meters, which will be computer-based and not include any mechanical parts. Based on this expectation, the Companies estimate a benefit of approximately $996,000.

c. Contact Center

Currently, calls to the Companies' Contact Center are handled by either the Interactive Voice Response ("IVR") system or CSRs (customer service representatives).[46] It is expected that calls related to billing accuracy will be reduced by 50% as a result of more accurate and timely billing, and calls related to connect/disconnect will be reduced by 45% as a result of the capability of the new meters to be connected remotely. These billing accuracy and remote connection improvements will result in total labor reductions of the Companies' CSRs of 16 FTEs, with the total correlating value for these reductions being approximately $30.4 million, as shown in Table 50, below.

CSR Labor Reduction from Billing and Service Reconnect Calls (Nominal $000s)	
Benefit Area	Value
Avoided CSR Billing Accuracy Calls	15,196
Avoided CSR Reconnection Calls	15,196
20-Year Total Billing and Scheduling Calls Benefits	**30,392**

Source: B.C.1, B.C.2 in Attachment 8

Table 50

v. Avoided CSR Billing Accuracy Calls

Eight of the 16 reduced FTEs discussed above are attributable to improved billing accuracy. Using the contact center call statistics as the basis for this estimate, a total of approximately 260,000 calls are anticipated to be related to billing accuracy – of which 73% (approximately 190,000) will be handled by CSRs, and the other 27% (approximately 70,000) will be handled by the IVR system. Although the volume of calls to the Contact Center is anticipated to be reduced by 50% (to approximately 130,000), the percentage handled by CSRs is expected to increase from 73% to 90% (to approximately 117,000) and IVR calls to decrease from 27% to 10% (to approximately 13,000) as a result of the increased complexity of the calls requiring more direct representative involvement versus the IVR system.

The combined impact of this results in a 38% reduction (190,000 to approximately 117,000) in estimated annual call volume handled by CSRs that is specific to billing accuracy inquiries. After applying an average handling time of nine minutes per call, dividing that by the amount of minutes per year a CSR handles the calls (removing the calls that are still expected for non-smart meter billing inquiries),[47] and applying the average annual costs per CSR FTE, the net amount of calls attributed to CSRs reduces the required number of FTEs needed by eight. The benefit of this FTE reduction is approximately $15.2 million.

[46] The Companies' contact center received roughly 827,000 calls in 2014, of which roughly 605,000, or 74%, were handled by CSRs. The remaining calls were handled through the IVR system. Of the calls handled by a CSR, approximately 190,000 were related to billing accuracy, 107,000 related to connect/disconnect, 184,000 related to payments and the remaining 124,000 were related to other categories.
[47] The Companies estimate that 3% of customers will participate in the proposed NSM tariff, with an additional 1% of meters classified as non-communicating due to geographic isolation.

vi. Avoided CSR Reconnection Calls

The other eight reduced CSR FTEs are attributable to increased use of the IVR system for reconnects as a result of the new remote reconnection capability. Using the contact center call statistics from 2014 as the basis for this estimate, a total of approximately 146,000 calls are anticipated to be related to reconnect requests – of which 73% (approximately 107,070) will be handled by CSRs, and the other 27% (approximately 39,000) will be handled by the IVR system. Based on experiences at other utilities,[48] the Companies expect that with AMI, the total annual calls related to service reconnection will remain constant. However, the percentage of service reconnect calls handled by CSRs will decrease by 45% (to approximately 66,000), as a result of the increased use of the IVR system for service restoration requests.

The impact of this reduction in service restoration calls results in a 50% reduction in call volume handled by CSRs annually. After applying the average handling time of seven minutes per call, dividing that by the number of minutes per year a CSR spends resolving reconnection issues, and applying the average annual cost per CSR FTE, the net amount of calls required reduces the number of CSR FTEs by eight. The benefit of this reduction is approximately $15.2 million.

d. <u>System Operations</u>

The types of outages experienced by customers can be broken down into three general categories: (1) “standard” outages that occur as a result of unavoidable power loss due to storms or other natural events; (2) “customer” outages related to overloaded breakers; and (3) “re-energizing” outages that occur when power is purposely turned off then back on during peak demand to avoid blackouts.

The systems operations benefits result from a reduction of current expenditures that will no longer be required once the smart meters are installed. As explained below, these benefits correlate directly with the annual cost of license maintenance fees associated with the use of existing AMR Turtle meters in the event of “re-energizing” outages at Maui Electric and Hawai‘i Electric Light. Such AMR Turtle meters are not in use at Hawaiian Electric and therefore, these benefits are not expected on O‘ahu.

With the remote reconnect capabilities enabled by AMI, the Companies estimate that there will be a reduction in the amount of overtime required at Maui Electric to reconnect power due to “re-energizing outages,” as well as an elimination of the need for future investment in AMR Turtle meters at Hawai‘i Electric Light and Maui Electric, as shown in Table 51, below.

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[48] Based on consulting experience at Southern California Edison and Pacific Gas & Electric business case estimates.

Improved System Operations (Nominal $000s)	
Benefit Area	Value
Avoided Maui Electric Overtime Meter Activation Labor	926
Avoided Maui Electric and Hawai‘i Electric Light AMR Turtle PLC System Fees	556
20-Year Total Improved System Operations Benefits	**1,482**

Source: B.S.5, B.S.6 in Attachment 8

Table 51

i. Avoided Maui Electric Overtime Meter Activation Labor

This benefit is from a reduction of overtime expenditure currently incurred at Maui Electric for weekend and/or after hours work required for connection and disconnection of meters. Currently, only Maui Electric utilizes overtime and weekends for connection and disconnection of service due to resource constraints, while Hawaiian Electric and Hawai‘i Electric Light perform this work during normal business hours. For each of these types of service requests, the hourly overtime rate varies depending on whether the request occurs at the end of a shift ($66/hour) or over the weekend ($89/hour). In 2014, approximately 17.8% of these requests occurred at the end of a shift.

As a result of the remote capability to connect and disconnect the new meters, the current time and expenditure associated with these requests will no longer be required. The estimated value of the reduction in overtime labor is approximately $926,000.

ii. Avoided Maui Electric and Hawai‘i Electric Light AMR Turtle PLC System Fees

The second smart meter benefit relates to the avoided investment in AMR Turtle meters due to the deployment of AMI at Maui Electric and Hawai‘i Electric Light. In 2015, the total fees for the AMR Turtle meters accounted for $9,000 at Maui Electric and $12,500 at Hawai‘i Electric Light. Since the smart meters being deployed as part of the AMI implementation will negate the need for these costs moving forward, the estimated value in the reduction of these fees is estimated at approximately $556,000.

e. Billing and Receivables

As discussed in Section II.B.7 above, the MDMS enabled by AMI will improve the Companies’ billing processes and perform meter-to-billing determinant processing. The benefits of these capabilities are related specifically to: (1) increased billing accuracy; (2) reduced bad debt; (3) reduced energy theft; and (4) improved collection of non-payment reconnect fees. As shown in Table 52 below, these benefits will reduce costs in the following areas:

Increased Billing Accuracy and Accounts Receivables (Nominal $000s)	
Benefit Area	Value
Overhead Reduction in Manual Processing of Bills	8,007
Reduction in Non-Paying Customer Costs	17,208
Avoided Energy Theft Costs	17,669
Increased Collection from Non-Paying Customers	2,291
20-Year Total Billing and Receivables Benefits	**45,175**

Source: B.B.1, B.B.5, B.B.3, B.B.10 in Attachment 8

Table 52

i. Overhead Reduction in Manual Processing of Bills

By automating the meter reading and billing processes, the MDMS will enable the Companies to reduce the potential for human error in reading meters. This improved accuracy of meter reads will in turn reduce the number of high/low implausible billing exception transactions through the MDMS, thus reducing the manual processing related to implausible exceptions, improving the Companies' billing department productivity and reducing staffing requirements.[49]

As of 2015, approximately 25,000 high/low implausible billing exceptions currently occur per month across the Companies, requiring an average of 1.5 minutes of handling time per exception call. It is estimated full installation of the smart meters and the related process changes will dramatically improve system performance and accuracy of the reads and these types of exceptions will be reduced by 80%. However, the average number of minutes required per call will increase to 2.5 minutes, due to the increased volume of data that the smart meters will provide.

As a result, the Companies anticipate that the total number of CSR FTEs needed to handle these exception calls will be reduced from 17 to 14, based on the total call volume reduction and the amount of hours annually a CSR FTE is available for these calls. The estimated value of this overhead cost reduction is approximately $8.0 million.

ii. Reduction in Non-Paying Customer Costs

The Companies' five-year average (2009-2015) annual bad-debt expense is $2.6 million, all of which was attributed to delinquent accounts. The remote disconnect capability will enable the Companies to enforce disconnects on delinquent accounts in a more timely fashion, thereby reducing costs associated with serving non-paying customers. Based on input from other utilities, the Companies estimate that these more timely disconnects will reduce bad debt expense by approximately 30%, or $17.9 million.

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[49] High/low implausible billing exceptions occur when a received meter read or invoiced amount falls outside of certain tolerated thresholds. It generates a case for the billing representative to review historical consumption and the invoiced amount to assess the reasonableness of the customer bill. Based on the review, it may result in the need to take a new read for validation purposes or to bill as is. In the existing non-smart meter case, the new read requires the meter reader to revisit the meter at the customer location to take the second read.

iii. Avoided Energy Theft Costs

The average annual level of energy theft recovered at the Companies over the last six years was approximately $268,000. The cost of energy theft is reflected in the revenue requirements approved in the Companies' general rate cases. Although reductions in energy theft do not present a monetary benefit to the Companies, they do result in a direct monetary benefit to customers. Accordingly, the value of energy theft reductions is reflected in this business case, but not as an offset to the proposed cost recovery through the Modified REIP Framework.

Based on input from other utilities, the Companies anticipate MDMS-related energy theft reductions from two areas: (1) a 100% elimination of the number of "leads" related to potential incidences of energy theft; and (2) an improvement from 18% to 27% in the accuracy of all identified leads. In other words, the volume of energy theft investigations will be doubled, and the proportion of those leads that identify actual energy theft will increase by 50%. Based on the Companies' historical levels of energy theft recovered between 2010 and 2015, the value of this benefit is estimated to be $17.7 million.

iv. Increased Collection from Non-Paying Customers

When electric service is disconnected and then reconnected as a result of a customer non-payment issue, the issue is either: (1) resolved via customer payment without a visit from a Field Services Representative; (2) resolved by a customer payment via a visit from a Field Services Representative; or (3) remains unresolved. Where a non-payment issue remains unresolved, the utility is both (a) unable to collect on the outstanding customer payment and (b) unable to disconnect service due to a lack of access to the meter.

One of the MDMS-related benefits of the SGF Project relates to the ability to resolve customer non-payment issues by remotely disconnecting meters that cannot currently be accessed. At the same time, after a meter is remotely disconnected, the Companies will be able to remotely reconnect service (following payment of outstanding amounts).

The current reconnection fee for a customer payment before a Field Services Representative visit is $25, and the reconnection fee for a customer payment made after a Field Services Representative visit is $45. As a result of the ability to remotely connect and disconnect service, Field Services Representative visits will no longer be needed to address customer non-payment issues. This will result in: (1) a $20 reduction per reconnection fee that would previously have been charged in connection with a Field Services Representative visit; and (2) an increase in the collection in fees that previously would not have been collected as long as the customer non-payment issue remained unresolved. The net impact of these is estimated to be an approximately $2.3 million increase in the overall level of collected reconnection fees.

v. Non-Quantified Benefits of AMI

In addition to the AMI benefits quantified above, it is expected that AMI will result in other benefits that cannot be reasonably quantified. For example, the Companies anticipate that the installation of AMI will result in an increase in customer satisfaction due to more accurate bills and reduced call wait times. Although the Companies do assess customer satisfaction as part of their overall annual internal evaluations, it would be difficult (if not impossible) to identify what aspects of this metric are attributable to AMI as opposed to factors other than AMI. As a result, the Companies have not quantified the value of this benefit.

2. Customer Facing Solutions

The Commission's Inclinations specifically identify offering web portals for customers to access and view energy consumption data as a key component of a customer-focused AMI program.[50] As discussed above, the CFS subproject will offer the energy usage information that is collected through the MDMS to customers through an enhanced online customer energy portal that will provide the opportunity for customers to reduce their energy usage by introducing more interactive management tools made available to them through this solution. Although the Companies do not expect the CFS to result in any Operational Benefits to the Companies, the Companies do expect the CFS to play a major role in expanding choices and offering tools that will empower customers to better manage their energy usage and electricity expenses by accessing new innovations in energy management options and ultimately lowering customer bills.

Given that the CFS benefit is not expected to impact revenue requirements, the value of this subproject has been estimated from the perspective of customers – that is, the value to customers of using real-time energy usage information to reduce energy waste and maximize energy bill savings. Based on research of experiences with similar solutions at other utilities, industry studies,[51] input from NextEra Energy, Inc. and other factors unique to the Companies' service territories, the Companies estimate the monetary value of the CFS subproject Customer Benefit over the 20-year life of the SGF Project to be approximately $150 million.

As shown in Table 53 below, the CFS Customer Benefit was estimated by beginning with the anticipated customer participation rate for the CFS (i.e., the percentage of customers who participate in solutions and options provided through the portal) of 15%, which is expected to be the same for both residential and commercial customers. Although participation rates experienced on the mainland have generally been in the 20%-25% range, based on the Companies' experiences in Hawai'i, including results of the Initial Phase, the Companies believe that a 15% participation rate assumption better reflects the likely adoption of CFS in their service territories.

Next, the participation rate was multiplied by the average anticipated energy savings for participating residential and commercial customers. Data from implementations on the mainland indicates historical savings of approximately 7% for residential customers and 3.5% for commercial customers, although the savings have varied from utility to utility. Based on studies performed by the Companies and other industry information, the Companies anticipate energy savings of 4% for participating customers in Hawai'i (both residential and C&I).

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[50] See, e.g., pages 14-15 of Exhibit A to Decision and Order No. 32052, filed April 28, 2014 in Docket No. 2012-0036.
[51] See, e.g., Karen Ehrhardt-Martinez, Kat A. Donnelly & John A. "Skip" Laitner, *Advanced Met ering Initiatives and Residential Feedback Programs: A Meta-Review for Household Electricity-Saving Opportunities*, American Council for an Energy-Efficient Economy (June 2010).

Multiplying the anticipated participation rate of 15% by the average expected participant savings of 4% results in overall estimated customer energy savings of 0.6%. When applied to the Companies' 20-year sales forecasts, the average energy savings per customer over the 20-year life of the SGF Project is approximately $57. The nominal value of this customer benefit translates to approximately $150 million. However, because this is only a monetary benefit to customers (as opposed to a reduction in revenue requirements), the value of this benefit is not included as an offset for purposes of cost recovery through the Modified REIP Framework or future rate cases; the value is only taken into account for purposes of evaluating the overall business case of the SGF Project, as discussed in Section IV below. However, this benefit will be operationally measured, monitored and reported on, specifically as it relates to the percentage participation of customers and their overall energy usage trends.

CFS Subproject Customer Benefits (Nominal $000s)	
Expected Participation Rate	15%
Estimated Average Participant Savings	4%
Average Savings per Customer	0.6%
20-Year Average Savings per Customer	$105
Total 20-Year CFS Customer Benefits	**150,257**

Source: B.P.1 in Attachment 8

Table 53

It should be noted that in addition to reducing customer bills, the CFS will result in significant intangible benefits to customers, the Companies and State energy policy goals. For example, by making feedback on energy usage more convenient, engaging and beneficial to customers, the programs enabled by CFS will help the Companies to more successfully inform, engage, empower and motivate customers, which will increase customer satisfaction and support the transformation to a modern utility of the future. Although increased customer satisfaction benefits both customers and the Companies, that benefit is considered intangible and thus has not been quantified for purposes of this analysis.

3. Conservation Voltage Reduction

As discussed in Section II.B.3 above, CVR will enable the Companies to adjust distribution transformers to lower voltage levels and decrease customers' energy consumption. The Customer Benefits of the CVR subproject represent one of the largest economic benefits offsetting the costs to customers of the overall SGF Project. Based on analyses from the Companies' consultants DVI (see Attachment 9), Black & Veatch (see Attachment 10), and additional field testing (which is in progress), the Companies estimate the nominal value of the CVR benefit over the 20-year life of the SGF Project investment to be approximately $384 million.

The CVR benefit was estimated by beginning with a CVR factor, which is the ratio between voltage reduction and energy load consumption:

CVR Factor = % change in energy load consumption / % change in voltage reduction

Based on input from DVI and the results from the Initial Phase, the Companies estimate that the SGF Project will result in a CVR factor of 0.9 on a typical circuit where CVR is implemented (i.e., on O‘ahu, Maui and Hawai‘i Island). The CVR factor was then multiplied by the estimated difference between circuit voltages with CVR and without CVR of 1.8%,[52] to arrive at an overall estimated energy savings (kWh) of 1.62%. At a high level and as depicted in Table 54 below, the 1.62% in overall energy savings was applied to the marginal cost to produce electricity over the life of the SGF Project investment to derive the total nominal CVR benefit estimate of approximately $383.6 million.

CVR Subproject Benefits (Nominal $000s)		
CVR Factor		0.9
% Voltage Reduction	X	1.8%
% Energy Savings	=	1.62%
20-year CVR Benefit	=	$383,609

Source: B.A.1 in Attachment 8

Table 54

This energy savings benefit will be reflected as a reduction in fuel expense that can be passed through to customers through the Energy Cost Adjustment Clause and therefore, it does not flow through the proposed Modified REIP surcharge. It is however, a benefit that will be operationally measured, monitored and reported on – specifically as it relates to the CVR factor and the average voltage reduction achieved.

4. Direct Load Control

As discussed in Section II.B.4 above, the scope of the SGF Project includes the replacement and upgrade of the 32,000 one-way DLC switches that are currently installed in connection with the EnergyScout DLC program on O‘ahu.[53] Replacing the existing one-way switches with new two-way switches will not only extend the duration of the Companies' DLC capabilities, but also facilitate more accurate load curtailment forecasting, which will enhance the efficiency and effectiveness of direct load control activities.

As a result of the cost of the new switches being included in the SGF Project cost, the benefit of continuing the EnergyScout program has been included in this analysis. This benefit has been calculated using the methodology for valuing DR programs described in Chapter 5 of the IDRPP, spread across the 32,000 current devices, to reach the nominal estimated benefits of approximately $26.2 million, as shown in Table 55.[54]

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[52] The estimated range of voltages with CVR is 121.5 volts to 123.25 volts. The estimated range of voltages without CVR is 119.5 volts to 119.5 volts. Thus the estimated voltage reduction could range between 1% and 3%. The Companies selected 1.8% based on results from current field trials on the circuits in Pearl City, which is near the center of the estimated ranges.

[53] It is currently assumed that this DR program will continue unless specifically addressed and changed in the DR Portfolio docket.

[54] The proportion of the benefit allocated to the SGF Project is based on the percentage of the total EnergyScout water heater program costs to be funded under the SGF Project.

DLC Subproject Benefits (Nominal $000s)	
Annual Value of All DR-Related Avoided Generation (as of 2021)	2,959
Proportion Attributable to SGF Project	43%
Annual Value of DR-Related Avoided Generation Attributable to SGF Project (as of 2021)	1,391
20-Year Total Direct Load Control Program Benefits	**26,212**

Source: B.R.1 in Attachment 8

Table 55

The DLC benefit of the SGF Project relates to avoided costs, which do not impact revenue requirements. As a result, the DLC benefit is not considered an Operational Benefit, and has been excluded as a benefit for purposes of the Modified REIP Framework. The DLC subproject benefit has, however, been taken into account for purposes of the overall SGF business case, as the resultant avoided costs represent costs that will not need to be passed to customers in the future.

a. *Non-Quantified Benefits of Direct Load Control*

Although more accurate load curtailment forecasting should also provide some level of financial benefit, the Companies are not aware of any methodology for reasonably estimating the value of such a benefit. Therefore, the value of more accurate load curtailment forecasting is not reflected in the accompanying cost-benefit model. In addition, the new DLC switches should enable the Companies to offer customers a more robust suite DR programs, but the associated benefits specific to these programs have not been quantified.

5. Outage Management Systems

The ability to communicate with and “ping” smart meters, as well as the expansion of O‘ahu’s existing OMS to Maui Electric and Hawai‘i Electric Light, will provide enhanced capabilities for outage management across the Companies’ service territories, where many of these assessments still heavily rely on manual processes and/or notification of a service interruption by customers as they occur. These capabilities will reduce service restoration times by permitting the Companies to more precisely locate outages in a suspected outage area. Expanding the OMS to the neighbor islands will also increase productivity by introducing more efficient crew and dispatch management processes.

As shown in Table 56 below, the benefits of the OMS consist of both Operational Benefits and Customer Benefits. The Operational Benefits relate to Meter and Field Services efficiency improvements that will reduce revenue requirements by approximately $502,000 per year, and are thus, included as an offset to costs for purposes of the Modified REIP Framework surcharge. The Customer Benefit relates to improved value of service of $221,000 per year, as derived by the United States Department of Energy’s ICE Calculator.[55] Over the 20-year life of the investment, the combined value of the OMS Operational Benefits and Customer Benefits is estimated to be approximately $17.3 million.

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[55] The ICECalculator is an online tool for calculating service interruption cost estimates available at http://icecalculator.com/.

OMS Subproject Benefits (Nominal $000s)	
Benefit Area	Value
Annual Neighbor Island Cost Reduction	502
Annual Improved Value of Service	221
Total 20-Year OMS Benefits	**17,272**

Source: B.A.2 in Attachment 8

Table 56

Similar to the CFS benefit discussed above, the OMS Customer Benefit does not impact the Companies' revenue requirements. As a result, although the combined OMS benefit has been taken into account for purposes of evaluating the overall SGF Project business case, only the Operational Benefit (and not the Customer Benefit) is included as an offset to the OMS subproject costs in the Modified REIP Framework.

6. Existing Internal Labor Offset

The SGF Project will utilize certain internal labor resources, a portion of the costs of which are currently included in base rates as expense. When these resources work on the project, the Companies' accounting policies for capital and software development projects require that their work be classified as capital or deferred work (e.g., meter installation). Including costs that are already in base rates as capital costs for the SGF Project would result in double recovery of these labor resources. In order to address this issue, the Companies have included the incremental costs of this labor as a benefit (i.e., the "Existing Internal Labor Offset") that will offset surcharge recovery under the Modified REIP Framework. The value of this offset is estimated to be approximately $9.9 million as shown in Table 57 below. If the labor resource that is currently included in base rates is back-filled, then the cost would not be included in benefits offset.

Internal Labor Offset Benefits (Nominal $000s)	
Component	Value
AMI	6,952
CFS	248
CE	45
CVR	1,909
DLC	210
EDW	71
ESB	66
MDMS	285
OMS	106
Total	**9,892**

Table 57

IV. SGF PROJECT ECONOMIC ANALYSIS

A. CONTEXT OF THE SGF PROJECT

When viewed in isolation, the SGF Project does not have a positive business case. As explained in the Companies' Smart Grid Roadmap, the value proposition for a Smart Grid is unique in that many of its related benefits are community based, complex and/or difficult to directly quantify. Building a Smart Grid in Hawaiʻi will not be accomplished in a single project effort, but will evolve over time, growing and layering capabilities and functionality that increasingly deliver incremental value to customers.

The SGF Project will serve as the platform upon which the Companies will build their Smart Grid. Each additional component that is layered over the SGF Project platform will leverage existing capabilities, thereby increasing the value of the infrastructure already in place. When taken in their entirety, the overall bundle of benefits and capabilities enabled by Smart Grid supports an overall positive business case that will increase capabilities and lower costs in the long run.

B. SGF PROJECT PRESENT VALUE COSTS AND BENEFITS

In order to evaluate the overall financial impact of the SGF Project on a typical residential customer, the Companies have performed an "economic analysis" that nets the twenty-year SGF Project costs, ongoing expenses and post-in-service costs against its Operational Benefits and Customer Benefits, taking into account the time-value of money. Unlike a traditional revenue requirements analysis, this economic analysis models Customer Benefits of the SGF Project as if they were Operational Benefits in order to simulate the financial impact of the SGF Project from a customer perspective. (A traditional revenue requirements analysis of the SGF Project is provided in Exhibit G to the accompanying Application.)

As detailed in Section I.C above, the SGF Project is scheduled to be implemented over a five-year period at a cost of $340 million. Once placed in service, the Companies estimate that an additional $345 million of ongoing costs will need to be incurred over the anticipated 20-year asset life to support and maintain the investment. Another $51 million of post-in-service costs will be incurred in connection with the accelerated depreciation of the Companies' existing non-smart meters. Although these ongoing expenses and post-in-service costs are not included for purposes of the SGF Project cost estimate, they <u>are</u> included for purposes of evaluating the economics of the SGF Project as a stand-alone investment. Accordingly, this economic analysis assumes a total 20-year economic cost of $786 million in nominal dollars ($340 million + $345 million + $51 million), and $413 million on a present value basis.

As detailed in Section III above, the total quantified Operational Benefits and Customer Benefits of the SGF Project on a stand-alone basis over the 20-year asset life (2017-2036) is \$877 million in nominal dollars, and \$345 million on a present value basis. As shown in Figure 9 below, the largest drivers of the quantified benefits are anticipated to arise out of the CVR and AMI subprojects.[56]

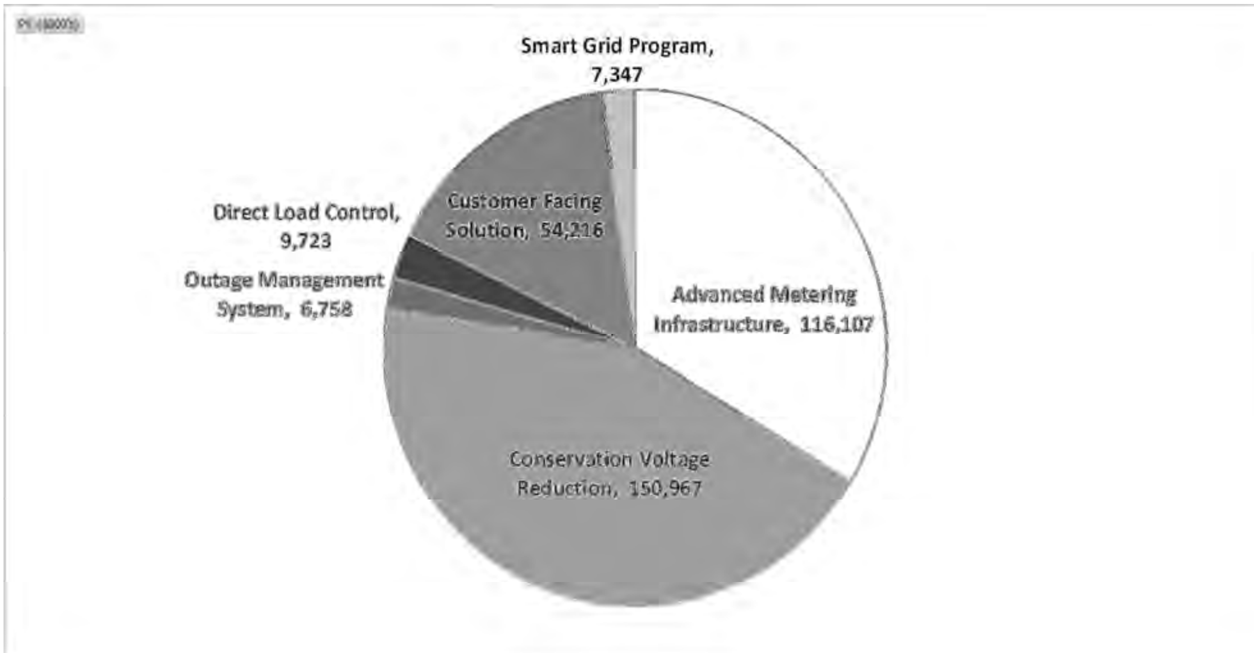

Figure 9

C. NET COSTS AND BENEFIT-TO-COST RATIO

The stand-alone present value of the SGF Project costs, ongoing expenses and post-in-service costs (\$413 million) netted against the SGF Project Operational Benefits and Customer Benefits (\$345 million) is negative \$68 million, reflecting a benefit-to-cost ratio of 0.84. However, the Companies reiterate that this present value does not take into account the monetary benefits of other initiatives that will build on the capabilities enabled by the SGF Project, including their DER Aggregator Contracts, DR Program Portfolio, DRMS Project, EV Time-of-use Rate Schedules, DER Time-of-use Rate Schedules, RTP Tariff, DA Project, DER Phase 1 and DER Phase 2.

D. CUSTOMER ECONOMIC IMPACT DETAILS

As shown in Figure 10 below, the economic analysis indicates that over the 20-year life of the investment, the SGF Project will cost (net of Operational Benefits and Customer Benefits)

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[56] The Companies have in the past evaluated projects using a present value of revenue requirements analysis that strictly quantifies the Operational Benefits of systems such as their proposed enterprise resource planning/enterprise asset management system (see Docket No. 2014-0170). The SGF Project is different from a pure business system in that many of the benefits inure directly to customers. In addition to the Operational Benefits associated with the AMI and OMS subprojects, as well as the internal labor offset, this analysis also accounts for customer benefits related to the CFS, CVR, DLC and OMS subprojects.

a typical residential customer using 500 kWh per month on average \$0.23/month at Hawaiian Electric, \$0.35/month at Maui Electric and \$0.20/month at Hawai'i Electric Light, with overall cost reductions beginning in the 2029-2030 timeframe. At Hawaiian Electric, the monthly economic impact on a typical residential customer will peak in 2022 at \$1.73/month, transition into net savings in 2029 and result in peak savings of \$1.59/month in 2036. At Maui Electric, the monthly economic impact on a typical residential customer will peak in 2022 at \$1.71/month, transition into net savings in 2030 and result in peak savings of \$1.15/month in 2034. At Hawai'i Electric Light, the monthly economic impact on a typical residential customer will peak in 2020 at \$2.39/month, transition into net savings in 2029 and result in peak savings of \$2.35/month in 2036.

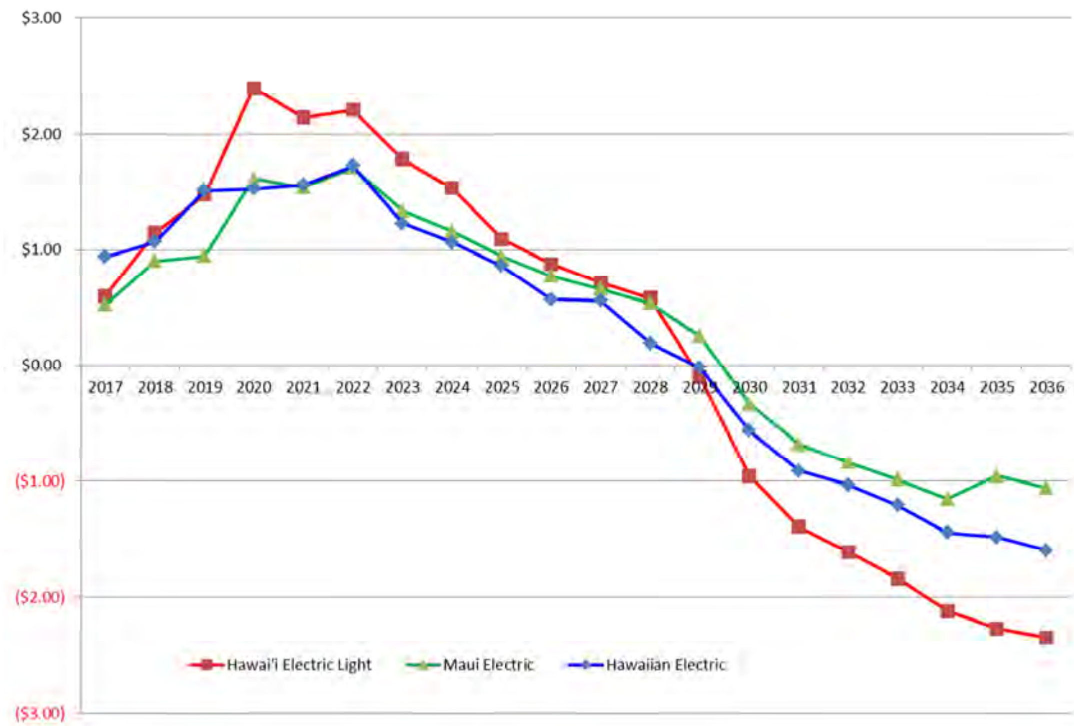

Figure 10

Additional details regarding the economic impacts illustrated above are provided in Attachment 11.

V. <u>CONCLUSION</u>

Throughout its progressive implementation, Smart Grid will play an increasingly pivotal role in Hawai'i's energy future. The SGF Project is the precedent platform to support the Companies' current and future Smart Grid initiatives. In the near term, the economic benefits enabled by the SGF Project will help to mitigate the economic impact of the SGF Project on customer bills. In the longer term, the overall bundle of benefits and capabilities enabled by Smart Grid supports a positive business case that will increase grid flexibility, reliability and transparency, and lower electricity costs for customers. The Companies look forward to working with the Commission, Consumer Advocate and other stakeholders to make Hawai'i's Smart Grid a leading model within the industry.

Attachment 1

Smart Grid Foundation Project

Exhibit B

Hawaiian Electric Companies' Project Management Office Cost Details

HAWAIIAN ELECTRIC COMPANIES' PROJECT MANAGEMENT OFFICE COST DETAILS

The Hawaiian Electric Companies' ("Companies") Project Management Office ("PMO") costs are a combination of internal labor and outside services. The methodology for allocating the PMO costs across each component was to calculate a percentage of total cost by component, then within each component calculate the percentage of component cost for each accounting treatment category (i.e., Capital, Deferred and Expense).

Tables 1 and 2 below show the PMO breakouts by component and accounting treatment, which are included in the costs presented within each component discussed in Section II.B in the accompanying Exhibit.

Total SGF Project PMO Costs by Company and Component (Nominal $000s)				
Component	Hawaiian Electric	Hawai'i Electric Light	Maui Electric	Total
AMI	3,333	1,261	995	5,590
CFS	259	-	-	259
CVR	503	214	185	902
DLC	1,026	-	-	1,206
EDW	380	-	-	380
ESB	357	-	-	357
MDMS	1,258	-	-	1,258
OMS	48	213	213	474
CE	222	33	33	288
Total	**7,386**	**1,721**	**1,426**	**10,534**

Table 1

Total SGF Project PMO Costs by Company and Accounting Treatment (Nominal $000s)				
Company	Capital	Deferred	Expense	Total
Hawaiian Electric	4,224	1,644	1,518	7,386
Hawai'i Electric Light	1,297	133	291	1,721
Maui Electric	1,001	133	291	1,426
Total	**6,523**	**1,911**	**2,100**	**10,534**

Table 2

Table **3** provides the total consolidated PMO costs by year.

Total Consolidated SGF Project PMO Costs by Year (Nominal $000s)						
Component	2017	2018	2019	2020	2021	Total
AMI	1,314	1,512	1,502	803	459	5,590
CFS	84	45	71	59	-	259
CVR	154	210	134	210	194	902
DLC	13	9	7	604	393	1,026
EDW	54	39	53	139	95	380
ESB	100	32	43	95	88	357
MDMS	495	403	359	-	-	1,258
OMS	62	135	277	-	-	474
CE	68	45	53	81	40	288
Total	**2,346**	**2,430**	**2,499**	**1,991**	**1,268**	**10,534**

Table 3

The following tables split these costs out by year and type for each component individually.

AMI Component PMO Costs by Year (Nominal $000s)						
	2017	2018	2019	2020	2021	Total
Internal Labor	**855**	**984**	**978**	**508**	**413**	**3,737**
Capital	747	921	896	337	253	3,153
Deferred	20	7	3	4	1	35
Expense	88	56	79	167	160	549
Outside Services	**460**	**528**	**524**	**295**	**45**	**1,852**
Capital	400	493	480	196	28	1,597
Deferred	13	4	2	3	-	22
Expense	47	30	42	97	18	234
Total	**1,314**	**1,512**	**1,502**	**803**	**459**	**5,590**

Table 4

CFS Component PMO Costs by Year (Nominal $000s)						
	2017	2018	2019	2020	2021	Total
Internal Labor	**53**	**28**	**45**	**36**	**-**	**162**
Deferred	37	17	34	10	-	99
Expense	16	10	10	26	-	63
Outside Services	**32**	**17**	**27**	**22**	**-**	**97**
Deferred	23	11	21	7	-	62
Expense	9	6	6	15	-	35
Total	**84**	**45**	**71**	**59**	**-**	**259**

Table 5

CVR Component PMO Costs by Year (Nominal $000s)						
	2017	2018	2019	2020	2021	Total
Internal Labor	**100**	**136**	**87**	**133**	**175**	**631**
Capital	92	107	70	97	139	506
Deferred	-	16	-	-	-	16
Expense	8	12	17	36	36	109
Outside Services	**54**	**74**	**47**	**77**	**19**	**271**
Capital	50	58	37	56	15	216
Deferred	-	10	-	-	-	10
Expense	4	7	9	21	4	45
Total	**154**	**210**	**134**	**210**	**194**	**902**

Table 6

DLC Component PMO Costs by Year (Nominal $000s)						
	2017	2018	2019	2020	2021	Total
Internal Labor	**9**	**6**	**4**	**382**	**354**	**755**
Capital	-	-	1	372	347	720
Deferred	6	3	-	-	-	9
Expense	3	3	3	10	7	26
Outside Services	**5**	**3**	**2**	**222**	**39**	**272**
Capital	-	-	-	216	38	255
Deferred	3	2	-	-	-	5
Expense	2	1	2	6	1	11
Total	**13**	**9**	**7**	**604**	**393**	**1,026**

Table 7

EDW Component PMO Costs by Year (Nominal $000s)						
	2017	2018	2019	2020	2021	Total
Internal Labor	**34**	**25**	**34**	**86**	**85**	**264**
Deferred	19	10	15	34	21	100
Expense	15	14	19	52	64	164
Outside Services	**20**	**14**	**19**	**53**	**10**	**116**
Deferred	12	7	9	23	3	53
Expense	8	8	10	30	7	63
Total	**54**	**39**	**53**	**139**	**95**	**380**

Table 8

ESB Component PMO Costs by Year (Nominal $000s)						
	2017	2018	2019	2020	2021	Total
Internal Labor	**63**	**20**	**27**	**59**	**79**	**248**
Capital	17	-	-	-	-	17
Deferred	39	8	11	22	27	107
Expense	6	13	17	36	51	123
Outside Services	**37**	**12**	**16**	**36**	**9**	**110**
Capital	9	-	-	-	-	9
Deferred	25	5	7	15	3	55
Expense	3	7	9	21	6	46
Total	**100**	**32**	**43**	**95**	**88**	**357**

Table 9

MDMS Component PMO Costs by Year (Nominal $000s)						
	2017	2018	2019	2020	2021	Total
Internal Labor	**307**	**250**	**224**	**-**	**-**	**781**
Capital	31	2	-	-	-	33
Deferred	257	214	172	-	-	644
Expense	19	34	52	-	-	105
Outside Services	**188**	**153**	**135**	**-**	**-**	**477**
Capital	17	1	-	-	-	18
Deferred	162	134	107	-	-	403
Expense	10	18	28	-	-	56
Total	**495**	**403**	**359**	**-**	**-**	**1,258**

Table 10

OMS Component PMO Costs by Year (Nominal $000s)						
	2017	2018	2019	2020	2021	Total
Internal Labor	**41**	**85**	**173**	**-**	**-**	**299**
Deferred	-	48	132	-	-	180
Expense	41	37	41	-	-	119
Outside Services	**22**	**50**	**104**	**-**	**-**	**176**
Deferred	-	30	82	-	-	112
Expense	22	20	22	-	-	63
Total	**62**	**135**	**277**	**-**	**-**	**474**

Table 11

Customer Engagement Component PMO Costs by Year (Nominal $000s)						
	2017	2018	2019	2020	2021	Total
Internal Labor (Expense)	45	29	35	51	36	196
Outside Services (Expense)	24	16	19	30	4	92
Total	**68**	**45**	**53**	**81**	**40**	**288**

Table 12

Attachment 2

Smart Grid Foundation Project

Exhibit B

Hawaiian Electric Companies' Cost Components by Company

HAWAIIAN ELECTRIC COMPANIES' COST COMPONENTS BY COMPANY

The spread of costs among the Hawaiian Electric Companies ("Companies") was utilized in order to ensure the spread of costs for the Smart Grid Foundation Project's ("SGF Project") implementation were fair and reasonable, and that customers from each utility would be able to realize the benefits that these components provide as quickly as possible. To that end, the Companies allocated the costs as shown in Table 1, below, with Hawaiian Electric bearing the majority of the costs for all of the components. This is true except for the Outage Management System ("OMS") component since its deployment during the SGF Project is to extend the existing OMS at Hawaiian Electric to Hawaiʻi Electric Light and Maui Electric. As such, the costs for the OMS component have been allocated to a majority share between Hawaiʻi Electric Light and Maui Electric, as shown below. Cost allocations by component and utility are further introduced in Section II of the accompanying Exhibit.

SGF Project Costs Allocation by Component[1]			
Component	Hawaiian Electric	Hawaiʻi Electric Light	Maui Electric
AMI	62%	21%	17%
CFS	100%	-	-
CVR	58%	23%	19%
DLC	100%	-	-
EDW	100%	-	-
ESB	100%	-	-
MDMS	100%	-	-
OMS	10%	45%	45%
CE	70%	15%	15%
Note: Includes PMO costs.			

Table 1

Sections I through III below show a breakout for each component's costs, by year, accounting treatment and utility, throughout the SGF Project implementation. These breakouts align with the overarching cost allocation assumptions for each utility provided above. Costs provided here are total costs for each component, inclusive of equipment, hardware, internal labor, maintenance, miscellaneous, outside services, software and AFUDC, where applicable.

I. HAWAIIAN ELECTRIC SGF PROJECT IMPLEMENTATION COSTS

The total nominal cost for the SGF Project's implementation specific to Hawaiian Electric is $240.4 million, or approximately 71% of the total SGF Project implementation costs, as shown in Table 2, below. The capitalized costs include equipment, warranty, hardware and labor for design, engineering, installation and management. The deferred costs include Stage 2 –

[1] Cost allocation percentages for AMI and CVR are represented in the table as averaged costs associated with these components for all three utilities. Specific costing and subsequent bill impact analysis have detailed these allocations down to each company independently for the most accurate estimated calculation and bill impact (see Section IV.C.1 of the accompanying Exhibit).

Application Development – software licensing, implementation, design, configure, coding, installing, integration, testing, train-the-trainer and management; Corporate Administration overhead was removed from the deferred labor costs. The expense costs include: 1) operational support, trouble-shooting, maintenance, analysis and firmware of capital equipment; 2) Stage 1 – Preliminary Project IT system costs; 3) Stage 3 Post-Implementation-Operation costs such as stabilization, end user training; 4) data capture, post-go-live software support, software maintenance after go-live and software-as-a-service ("SaaS") fees; and 5) Customer Engagement labor and outside services.

Hawaiian Electric SGF Project Implementation Costs by Accounting Treatment and Year (Nominal $000s)						
Accounting Treatment	2017	2018	2019	2020	2021	Total
Capital	49,500	40,051	14,051	14,640	13,884	132,126
Deferred	26,027	21,240	14,312	1,999	1,411	64,988
Expense	11,647	9,101	9,506	6,661	6,357	43,272
Total	**87,174**	**70,392**	**37,869**	**23,300**	**21,651**	**240,386**
Note: Includes PMO costs.						

Table 2

Table 3 below shows these costs by component and year for Hawaiian Electric during the SGF Project implementation.

Hawaiian Electric SGF Project Implementation Costs by Component and Year (Nominal $000s)						
Component	2017	2018	2019	2020	2021	Total
AMI	47,643	39,411	16,094	6,479	5,633	115,260
CFS	3,485	2,003	2,481	943	-	8,912
CVR	5,557	4,885	1,045	1,725	2,313	15,526
DLC	540	423	216	9,473	8,819	19,470
EDW	2,212	1,712	1,793	2,253	2,201	10,172
ESB	4,086	1,409	1,444	1,536	2,056	10,531
MDMS	20,701	18,519	12,505	-	-	51,725
OMS	322	703	1,089	-	-	2,114
CE	2,628	1,327	1,201	891	629	6,676
Total	**87,174**	**70,392**	**37,869**	**23,300**	**21,651**	**240,386**
Note: Includes PMO costs.						

Table 3

II. HAWAIʻI ELECTRIC LIGHT SGF PROJECT IMPLEMENTATION COSTS

The total nominal cost for the SGF Project implementation for Hawaiʻi Electric Light is $54.7 million, or approximately 16% of the total SGF Project's five-year implementation costs, as shown in Table 4, below. The capitalized costs include equipment, warranty, hardware and labor for design, engineering, installation and management. The deferred costs include Stage 2 –

Application Development – software licensing, implementation, design, configure, coding, installing, integration, testing, train-the-trainer and management; Corporate Administration overhead was removed from the deferred labor costs. The expense costs include: 1) operational support, trouble-shooting, maintenance, analysis and firmware of capital equipment; 2) Stage 1 – Preliminary Project IT system costs; 3) Stage 3 Post-Implementation-Operation costs such as stabilization and end-user training; 4) data capture, post-go-live software support, software maintenance after go-live and SaaS; and 5) Customer Engagement labor and outside services.

Hawai'i Electric Light SGF Project Implementation Costs by Accounting Treatment and Year (Nominal $000s)						
Accounting Treatment	2017	2018	2019	2020	2021	Total
Capital	1,410	15,480	19,088	2,862	2,736	41,576
Deferred	-	1,633	3,424	-	-	5,057
Expense	1,225	2,269	2,062	1,345	1,208	8,110
Total	**2,634**	**19,383**	**24,574**	**4,207**	**3,944**	**54,742**
Note: Includes PMO costs.						

Table 4

Table 5 provides these same costs by component and year.

Hawai'i Electric Light SGF Project Implementation Costs by Component and Year (Nominal $000s)						
Component	2017	2018	2019	2020	2021	Total
AMI	1,430	14,113	18,185	3,222	2,744	39,695
CFS	-	-	-	-	-	-
CVR	173	2,299	1,848	794	1,065	6,180
DLC	-	-	-	-	-	-
EDW	-	-	-	-	-	-
ESB	-	-	-	-	-	-
MDMS	-	-	-	-	-	-
OMS	1,031	2,686	4,283	-	-	8,000
CE	-	284	257	191	135	868
Total	**2,634**	**19,383**	**24,574**	**4,207**	**3,944**	**54,742**
Note: Includes PMO costs.						

Table 5

III. MAUI ELECTRIC SGF PROJECT IMPLEMENTATION COSTS

The total nominal cost for Maui Electric during the SGF Project five-year implementation is $44.9 million, or approximately 13% of the total implementation costs associated with the SGF Project. Table 6 below shows these costs broken out by accounting treatment and year, while Table 7 provides these costs by component and year. The capitalized costs include equipment, warranty, hardware and labor for design, engineering, installation and management. The deferred costs include Stage 2 – Application Development – software licensing, implementation, design, configure, coding, installing, integration, testing, train-the-trainer and management; Corporate Administration overhead was removed in deferred labor costs. The expense costs include: 1) operational support, trouble-shooting, maintenance, analysis and firmware of capital equipment; 2) Stage 1 – Preliminary Project IT system costs; 3) Stage 3 Post-Implementation-Operation costs such as stabilization and end user training; 4) data capture, post-go-live software support, software maintenance after go-live and SaaS fees; and 5) Customer Engagement labor and outside services.

Maui Electric SGF Project Implementation Costs by Accounting Treatment and Year (Nominal $000s)						
Accounting Treatment	2017	2018	2019	2020	2021	Total
Capital	1,404	11,325	14,845	2,498	1,775	31,847
Deferred	-	1,628	3,404	-	-	5,033
Expense	1,225	2,169	1,998	1,385	1,249	8,026
Total	**2,629**	**15,122**	**20,248**	**3,883**	**3,024**	**44,906**
Note: Includes PMO costs.						

Table 6

Maui Electric SGF Project Implementation Costs by Component and Year (Nominal $000s)						
Component	2017	2018	2019	2020	2021	Total
AMI	1,425	10,372	14,292	2,905	1,914	30,907
CFS	-	-	-	-	-	-
CVR	173	1,784	1,436	787	976	5,156
DLC	-	-	-	-	-	-
EDW	-	-	-	-	-	-
ESB	-	-	-	-	-	-
MDMS	-	-	-	-	-	-
OMS	1,031	2,681	4,264	-	-	7,976
CE	-	284	257	191	135	868
Total	**2,629**	**15,122**	**20,248**	**3,883**	**3,024**	**44,906**
Note: Includes PMO costs.						

Table 7

Attachment 3

Smart Grid Foundation Project

Exhibit B

Hawaiian Electric Companies' Internal Labor Details

HAWAIIAN ELECTRIC COMPANIES' INTERNAL LABOR DETAILS

As discussed in Section II.A.2.c of the accompanying Exhibit, the total internal labor costs calculated for the Smart Grid Foundation Project ("SGF Project") include incremental and non-incremental full-time equivalents ("FTEs") that account for approximately 911,000 hours, equating to roughly $74 million or 22% of the total project costs.[1] Table 1 shows a breakout of these estimated costs by utility and accounting treatment, while Table 2 depicts these costs by labor source, hours and accounting treatment as a consolidated representation. All tables provided show the estimated incremental labor that is not currently in the rate base and the non-incremental labor that is recovered in the rate base.

During the implementation of the SGF Project, non-incremental labor is utilized to perform capital and deferred work which requires re-classification of the labor in the accounting treatment. Generally, non-incremental labor has a mixture of capital and expense work depending upon the labor group and department. To prevent double recovery, a reduction in the rate base is captured in the benefits section of the accompanying Exhibit (see Section III.C). The amount of rate base reduction depends on how much of the non-incremental labor is being re-classified to capital or deferred.

These costs are inclusive of Project Management Office ("PMO") costs as these costs are spread through all nine components listed, as described in Section I.A.10 of the accompanying Exhibit. The internal incremental and non-incremental labor costs provided herein are representative of the internal labor cost category for each component described in Section II.B of the accompanying Exhibit.

Total SGF Project Internal Labor Costs by Company ($ Nominal)								
Component	Capital		Deferred		Expense		Total	
	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.
Hawaiian Electric	25,493	323,000	7,321	118,000	11,138	131,000	43,952	572,000
Hawai'i Electric Light	13,293	152000	920	13000	2,252	29000	16,465	194,000
Maui Electric	10,355	103000	920	13000	2,515	29000	13,790	145,000
Total	**49,141**	**578,000**	**9,161**	**144,000**	**15,905**	**189,000**	**74,207**	**911,000**

Table 1

[1] The fully loaded costs for the internal labor presented are inclusive of salaries and overhead, and were estimated using 1,900 annual working hours per FTE.

Consolidated SGF Project Internal Labor Costs by Accounting Treatment ($ Nominal)								
Component	Capital		Deferred		Expense		Total	
	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.
Incremental	13,475	194,000	4,759	83,000	11,630	157,000	29,864	434,000
Non-Incremental	35,666	384,000	4,402	61,000	4,275	32,000	44,343	477,000
Total	**49,141**	**578,000**	**9,161**	**144,000**	**15,905**	**189,000**	**74,207**	**911,000**

Table 2

Tables 3 through 11 break these costs out further specific to each component.

AMI Component Internal Labor Costs by Accounting Treatment ($ Nominal)								
Component	Capital		Deferred		Expense		Total	
	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.
Incremental	9,136	140,000	104	1,000	7,495	98,000	16,735	239,000
Non-Incremental	25,275	290,000	50	1,000	1,424	10,000	26,749	301,000
Total	**34,411**	**430,000**	**154**	**2,000**	**8,919**	**108,000**	**43,484**	**540,000**

Table 3

CFS Component Internal Labor Costs by Accounting Treatment ($ Nominal)								
Component	Capital		Deferred		Expense		Total	
	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.
Incremental	-	-	75	2,000	125	2,000	200	4,000
Non-Incremental	-	-	488	7,000	562	5,000	1,050	12,000
Total	**-**	**-**	**563**	**9,000**	**687**	**7,000**	**1,250**	**16,000**

Table 4

CVR Component Internal Labor Costs by Accounting Treatment ($ Nominal)								
Component	Capital		Deferred		Expense		Total	
	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.
Incremental	4,034	43,000	-	-	67	2,000	4,101	45,000
Non-Incremental	9,554	92,000	29	-	505	6,000	10,088	98,000
Total	**13,588**	**135,000**	**29**	**-**	**572**	**8,000**	**14,189**	**143,000**

Table 5

DLC Component Internal Labor Costs by Accounting Treatment ($ Nominal)								
Component	Capital		Deferred		Expense		Total	
	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.
Incremental	305	11,000	-	-	-	-	305	11,000
Non-Incremental	720	1,000	12	-	26	-	758	1,000
Total	**1,025**	**12,000**	**12**	**-**	**26**	**-**	**1,063**	**12,000**

Table 6

EDW Component Internal Labor Costs by Accounting Treatment ($ Nominal)								
	Capital		Deferred		Expense		Total	
	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.
Incremental	-	-	863	15,000	933	12,000	1,796	27,000
Non-Incremental	-	-	100	1,000	123	1,000	223	2,000
Total	**-**	**-**	**963**	**16,000**	**1,056**	**13,000**	**2,019**	**29,000**

Table 7

ESB Component Internal Labor Costs by Accounting Treatment ($ Nominal)								
Component	Capital		Deferred		Expense		Total	
	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.
Incremental	-	-	1,015	17,000	303	5,000	1,318	22,000
Non-Incremental	66	1,000	108	1,000	165	1,000	339	3,000
Total	**66**	**1,000**	**1,123**	**18,000**	**468**	**6,000**	**1,657**	**25,000**

Table 8

MDMS Component Internal Labor Costs by Accounting Treatment ($ Nominal)								
Component	Capital		Deferred		Expense		Total	
	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.
Incremental	-	-	1,469	31,000	483	7,000	1,952	38,000
Non-Incremental	50	-	2,806	40,000	958	6,000	3,814	46,000
Total	**50**	**-**	**4,275**	**71,000**	**1,441**	**13,000**	**5,766**	**84,000**

Table 9

OMS Component Internal Labor Costs by Accounting Treatment								
Component	Capital		Deferred		Expense		Total	
	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.
Incremental	-	-	1,233	17,000	375	6,000	1,608	23,000
Non-Incremental	-	-	808	11,000	317	3,000	1,125	14,000
Total	**-**	**-**	**2,041**	**28,000**	**692**	**9,000**	**2,733**	**37,000**

Table 10

Customer Engagement Internal Labor Costs by Accounting Treatment								
Component	Capital		Deferred		Expense		Total	
	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.	$000s	Hrs.
Incremental	-	-	-	-	1,849	25,000	1,849	25,000
Non-Incremental	-	-	-	-	196	-	196	-
Total	**-**	**-**	**-**	**-**	**2,045**	**25,000**	**2,045**	**25,000**

Table 11

Attachment 4

Smart Grid Foundation Project

Exhibit B

Hawaiian Electric Companies' Loaded Labor Rates

HAWAIIAN ELECTRIC COMPANIES' LOADED LABOR RATES

Company	Job Description	Loaded Labor Rate
HE	Supervising Facilitator	$ [redacted]
HE	Analyst/PM/ Practitioner	$ [redacted]
HE	Instrument & Controls Technician	$ [redacted]
HE	Instrument & Controls Engineer	$ [redacted]
HE	Instrument & Controls Supervisor	$ [redacted]
HE	Communications Tech	$ [redacted]
HE	Communications Engineer	$ [redacted]
HE	Communications Supervisor	$ [redacted]
HE	Lineman	$ [redacted]
HE	Trouble-man	$ [redacted]
HE	Meter Supervisor	$ [redacted]
HE	Meter Electrician	$ [redacted]
HE	Meter Engineer	$ [redacted]
HE	PP Travel Electricians	$ [redacted]
HE	Support Service Electrician	$ [redacted]
HE	T&D Design	$ [redacted]
HE	T&D Drafting	$ [redacted]
HE	Field Service/ Meter Clerks	$ [redacted]
HE	Tech Service Support	$ [redacted]
HE	Structural Support	$ [redacted]
HE	Joint Pole Aide	$ [redacted]
HE	System Operations Engineer	$ [redacted]
HE	Operations Analyst	$ [redacted]
HE	Operations Dispatch	$ [redacted]
HE	Sub Engineer	$ [redacted]
HE	Substation Crew	$ [redacted]
HE	Substation Supervisor	$ [redacted]
HE	Substation Planner	$ [redacted]
HE	Substation Engineer	$ [redacted]
HE	Relay Technician	$ [redacted]
HE	Relay Supervisor	$ [redacted]
HE	Relay Engineer	$ [redacted]
HE	Relay Lead Engineer	$ [redacted]
HE	Endpoint Monitor Supervisor	$ [redacted]
HE	Revenue Protection	$ [redacted]
HE	Distribution Planning	$ [redacted]
HE	ITS and IA	$ [redacted]
ME	Communications/ Electrician	$ [redacted]

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ME	Construction Supervisor	$	[redacted]
ME	Lineman/ Construction	$	[redacted]
ME	Electrical Mechanic or Test Engineer	$	[redacted]
ME	Trouble-man	$	[redacted]
ME	Meter Electrician	$	[redacted]
ME	Dispatch	$	[redacted]
ME	SCADA Engineer	$	[redacted]
ME	Clerk DBUOC	$	[redacted]
ME	Engineer II	$	[redacted]
ME	Electrical Engineer/Supervisor	$	[redacted]
ME	Drawing Management	$	[redacted]
ME	Revenue Protection	$	[redacted]
ME	Analyst/PM/ Practitioner	$	[redacted]
HL	Electrician	$	[redacted]
HL	Lineman/ Trouble-man	$	[redacted]
HL	Customer Planner	$	[redacted]
HL	Engineer/Supervisor	$	[redacted]
HL	Dispatch	$	[redacted]
HL	Materials & Record Keeper	$	[redacted]
HL	Revenue Protection	$	[redacted]
HL	Analyst/PM/ Practitioner	$	[redacted]
HL	Drafting Technician	$	[redacted]

Attachment 5

Smart Grid Foundation Project

Exhibit B

Hawaiian Electric Companies' Outside Services Cost Details

HAWAIIAN ELECTRIC COMPANIES' OUTSIDE SERVICES COST DETAILS

The total outside services cost category accounts for approximately $133 million, or roughly 39% of the total Smart Grid Foundation Project's ("SGF Project") implementation costs. As described in Section II.A.2 of the accompanying Exhibit, the Hawaiian Electric Companies ("Companies") have procured external vendors, either through existing contracts or via issued request for proposals ("RFPs"), to assist and manage certain aspects of the SGF Project implementation. A portion of these costs, which is comprised of primarily external labor, is included in the "outside services" cost category for each component detailed in Section II.B of the accompanying Exhibit.

Table 1 below, provides the overall consolidated outside services costs by accounting treatment and utility that will be incurred during the SGF Project's five-year implementation.

SGF Project Outside Services Costs by Accounting Treatment (Nominal $000)				
Company	Capital	Deferred	Expense	Total
Hawaiian Electric	41,913	47,123	14,315	103,351
Hawai'i Electric Light	8,055	3,528	3,959	15,543
Maui Electric	6,794	3,528	3,855	14,177
Total	**56,762**	**54,180**	**22,129**	**133,070**
Note: Includes PMO costs.				

Table 1

Tables 2 and 3 provide a breakout of the outside services costs for Hawaiian Electric by accounting treatment and component for each year of the SGF Project implementation.

Hawaiian Electric Outside Service Costs by Year (Nominal $000s)															
	2017			**2018**			**2019**			**2020**			**2021**		
Component	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp
AMI	16,114	1,245	2,539	9,093	395	502	4,132	168	509	837	87	489	434	0.08	451
CFS	-	2,171	303	-	1,163	352	-	1,713	174	-	206	172	-	-	-
CVR	975	-	4	341	1,172	4	35	-	5	125	-	13	176	-	2
DLC	[redacted]														
EDW															
ESB															
MDMS	323	11,834	10	1	12,513	525	-	7,708	555	-	-	-	-	-	-
OMS	[redacted]														
CE	-	-	2,110	-	-	975	-	-	835	-	-	504	-	-	603
Total	**17,830**	**17,149**	**5,560**	**9,435**	**16,700**	**3,007**	**4,168**	**11,165**	**2,594**	**5,739**	**1,344**	**1,657**	**4,741**	**765**	**1,496**
Note: Includes PMO costs.															

Table 2

Hawaiian Electric Outside Services Costs by Accounting Treatment (Nominal $000s)				
Component	Capital	Deferred	Expense	Total
AMI	30,610	1,895	4,490	36,995
CFS	-	5,253	1,001	6,254
CVR	1,652	1,172	29	2,853
DLC	[redacted]			
EDW				
ESB				
MDMS	324	32,054	1,090	33,468
OMS	[redacted]			
CE	-	-	5,027	5,027
Total	**41,913**	**47,123**	**14,315**	**103,351**
Note: Includes PMO costs.				

Table 3

Tables 4 through 7 below provide similar breakouts for both Hawai‘i Electric Light and Maui Electric during the SGF Project five-year implementation.

Hawai‘i Electric Light Outside Service Costs by Year (Nominal $000s)															
	2017			**2018**			**2019**			**2020**			**2021**		
Component	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp
AMI	1,021	-	169	2,270	-	279	3,414	-	283	215	-	190	95	-	171
CFS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CVR	142	-	-	266	-	2	270	-	2	177	-	4	184	-	0.8
DLC	[redacted]														
EDW															
ESB															
MDMS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OMS	[redacted]														
CE	-	-	-	-	-	209	-	-	179	-	-	108	-	-	129
Total	**1,163**	**-**	**1,182**	**2,536**	**1,049**	**1,380**	**3,684**	**2,479**	**793**	**392**	**-**	**302**	**279**	**-**	**301**
Note: Includes PMO costs.															

Table 4

Hawai‘i Electric Light Outside Services by Accounting Treatment (Nominal $000s)				
Component	Capital	Deferred	Expense	Total
AMI	7,016	-	1,093	8,109
CFS	-	-	-	-
CVR	1,039	-	9	1,048
DLC	[redacted]			
EDW				
ESB				
MDMS	-	-	-	-
OMS	[redacted]			
CE	-	-	625	625
Total	**8,055**	**3,528**	**3,959**	**15,543**
Note: Includes PMO costs.				

Table 5

Maui Electric Outside Service Costs by Year (Nominal $000s)															
	2017			2018			2019			2020			2021		
Component	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp
AMI	1,021	-	169	1,864	-	227	2,740	-	230	186	-	192	33	-	172
CFS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CVR	142	-	0.04	220	-	1	224	-	2	181	-	3	181	-	0.7
DLC	[redacted]														
EDW															
ESB															
MDMS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OMS	[redacted]														
CE	-	-	-	-	-	209	-	-	179	-	-	108	-	-	129
Total	**1,163**	**-**	**1,182**	**2,084**	**1,049**	**3,411**	**2,964**	**2,479**	**740**	**367**	**-**	**303**	**214**	**-**	**302**
Note: Includes PMO costs.															

Table 6

Maui Electric Outside Services Costs by Accounting Treatment (Nominal $000s)				
Component	Capital	Deferred	Expense	Total
AMI	5,844	-	990	6,834
CFS	-	-	-	-
CVR	949	-	7	956
DLC	[redacted]			
EDW				
ESB				
MDMS	-	-	-	-
OMS	[redacted]			
CE	-	-	625	625
Total	**6,794**	**3,528**	**3,855**	**14,177**
Note: Includes PMO costs.				

Table 7

Attachment 6

Smart Grid Foundation Project

Exhibit B

Hawaiian Electric Companies' Asset Life Details

HAWAIIAN ELECTRIC COMPANIES' ASSET LIFE DETAILS

Table 1 below shows the asset lives for the capital and deferred investments included in the Smart Grid Foundation Project ("SGF Project") cost estimate (i.e., equipment, hardware, and software) that were utilized to calculate the depreciation and amortization in the economic analysis (see Section IV of the accompanying Exhibit) and REIP Surcharge (see Exhibit G to the accompanying Application).

Component	Asset	Description	Functional Category	Asset Life (Years)
AMI	Access points and relays – network communications devices	Used to wirelessly connect devices on the Field Area Network	Communications	15
AMI	Network design and engineering	SSNI services to design the mesh network	Communications	15
AMI	Meter design and engineering	Meter engineering, testing and maintaining meter device inventory	Meter[1]	20
AMI	Meters, SSNI network interface card ("NIC")	Installation and oversight of residential and commercial and industrial ("C&I") meters with NICs	Meter[1]	20
AMI	Pole	Pole replacement due to overloading	Distribution	30
AMI	Firewall and switches – network communications devices	Assets to protect network from cyber-threats	Computer	9
CVR	Beckwith Electric Company, Inc. ("Beckwith") Controller	Beckwith Controller controls the transformer's load tap changer at the substation	Distribution	10
CVR	Dominion Voltage Incorporated ("DVI") Edge Server hardware and software SICAM device	DVI Edge server and SICAM interface hardware that monitors and calculates optimal voltage settings for circuits	Communications	6
CVR	Capacitor bank	Used to relay energy across long circuits; also includes automation to monitor and control voltage	Distribution[2]	55

Component	Asset	Description	Functional Category	Asset Life (Years)
EDW	Server hardware and operating software	Servers and storage for the EDW	Computer	6
EDW	Software application and development – EDW	Consolidates, stores and makes available data from multiple systems for analysis	Deferred	12
ESB	Software application and development – ESB	Interconnects data across multiple systems	Deferred	12
ESB	Server hardware and operating software	Servers and storage for the ESB	Computer	6
MDMS	Server hardware and operating software	Servers and storage for the MDMS	Computer	6
MDMS	Software application and development – MDMS	Controls billing determination and interval usage information	Deferred	12
CFS	Software development – CFS	Desktop and mobile (includes laptops, tablets and phones) interfaces of CFS	Deferred	12
OMS	Software application and development – OMS	Incremental software development adding to the existing Outage Management System	Deferred	12
OMS	Server hardware and operating software	Incremental servers and storage adding to the existing Outage Management System	Computer	6
DLC	Cooper two-way water heater switch from Eaton Corporation	DLC switches to control hot water heaters at residential sites	Communications	15
Notes: 1. Proposed smart meter asset life pending Commission approval. 2. Proposed capacitor bank asset life pending Commission approval.				

Table 1

Attachment 7

Smart Grid Foundation Project

Exhibit B

Hawaiian Electric Companies' Benefits Calculation Assumptions

HAWAIIAN ELECTRIC COMPANIES' BENEFITS CALCULATION ASSUMPTIONS

The follow assumptions were used in the calculation of the monetary benefits provided in Section III of the accompany Exhibit.

Drivers	Approach / Assumptions
Scope	Service Life: 20 years from 2017 to 2036; and Islands: O'ahu, Maui, Moloka'i, Lana'i, Hawai'i Island.
Financial	Long-term weighted average cost of capital: 8.076%; this is the standard company percentage used in current and prior modelling; Labor rates vary according to each role and are based on 2,080 annual hours; and Indirect labor costs vary by company and are added to base labor rates.
Number of Meters As of Dec. 1, 2015	Tri-Company Total: Residential – 436,536 and Commercial – 31,094 (Total of 467,630): Hawaiian Electric: Residential – 289,349 and Commercial – 19,927 (Total of 309,276); Hawai'i Electric Light: Residential – 81,235 and Commercial – 5,322 (Total of 86,557); and Maui Electric: Residential – 65,952 and Commercial – 5,845 (Total of 71,797).
Number of Customers As of Dec. 1, 2015	Tri-Company Total: Residential – 401,243 and Commercial – 55,782 (Total of 457,025): Hawaiian Electric: Residential – 269,938 and Commercial – 32,985 (Total of 302,923); Hawai'i Electric Light: Residential – 70,831 and Commercial – 12,880 (Total of 83,711); and Maui Electric: Residential – 60,474 and Commercial – 9,917 (Total of 70,391).
Inflation / Growth per	Gross Domestic Product Price Index (GDPPI) = 1.80%;

Year	Bargaining Unit ("BU") Labor Escalation = 1.50%; Non-BU Labor Escalation = 3.00%; and Annual Customer and Meter Growth Rates: Hawaiian Electric = 0.60%, Hawai'i Electric Light = 0.92%, Maui Electric = 0.95%.
AMI Non-Standard Meter Coverage	Percentage of residential non-standard meters ("NSM") that are in "non-communicating" areas is estimated at 1% across all five islands, based on the latest testing data and coverage as defined by SSNI.
AMI Non-Standard Meter (NSM) Service Program Participation	Residential NSM Service Program participant rates are assumed to decrease over four years for Hawaiian Electric, from 4% to 2%, then remain constant; Residential NSM Service Program participant rates are assumed to decrease over four years for Hawai'i Electric Light and Maui Electric, from 8% to 5%, then remain constant; and Commercial NSM Service Program participation rates are assumed to be 1% across all islands through 2036.
Generation	For purposes of calculating energy savings, forecasted cost generation assumptions are based on the interim data from the Companies' February 2016 Power Supply Improvement Plan filing.

Attachment 8

Smart Grid Foundation Project

Exhibit B

Benefits Model

The supporting attachments and workpapers that comprise the cost/Benefit Model do not lend themselves to printed form in a comprehensive fashion and will be provided electronically in a separate transmittal.

Attachment 9

Smart Grid Foundation Project

Exhibit B

Hawai‘i Electric Energy Savings Report

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Attachment 10

Smart Grid Foundation Project

Exhibit B

Hawaiian Electric Companies' Distribution Automation Strategy

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Attachment 11

Smart Grid Foundation Project

Exhibit B

Hawaiian Electric Companies' Economic Analysis Details

HAWAIIAN ELECTRIC COMPANIES' ECONOMIC ANALYSIS DETAILS

The Hawaiian Electric Companies ("Companies") performed an economic analysis to understand the impact of the Smart Grid Foundation Project ("SGF Project") through 2036 (timeframe representative of the longest useful life of the smart meters). The SGF Project is expected to nominally cost in revenue requirements ("RR") $62 million, $16 million, and $9 million at Hawaiian Electric, Maui Electric and Hawai'i Electric Light respectively. See detailed information in Table 1, below:

Year	Hawaiian Electric	Maui Electric	Hawai'i Electric Light	Consolidated
2017	12,241	1,173	1,201	14,615
2018	14,128	2,055	2,307	18,490
2019	20,176	2,170	2,994	25,341
2020	20,250	3,735	4,896	28,881
2021	20,623	3,568	4,386	28,576
2022	22,538	3,988	4,532	31,058
2023	15,952	3,142	3,666	22,760
2024	13,768	2,755	3,163	19,687
2025	11,052	2,263	2,245	15,561
2026	7,276	1,869	1,794	10,939
2027	7,121	1,595	1,448	10,165
2028	2,434	1,300	1,175	4,910
2029	(243)	598	(196)	159
2030	(7,013)	(775)	(1,874)	(9,661)
2031	(11,290)	(1,585)	(2,740)	(15,615)
2032	(12,985)	(1,959)	(3,172)	(18,116)
2033	(15,261)	(2,358)	(3,639)	(21,258)
2034	(18,441)	(2,820)	(4,237)	(25,498)
2035	(19,092)	(2,369)	(4,593)	(26,054)
2036	(20,806)	(2,683)	(4,822)	(28,311)
Total RR	**$62,428**	**$15,665**	**$8,536**	**$86,630**
Present Value Revenue Requirements ("PVRR")	**$84,743**	**$15,166**	**$15,152**	**$115,061**

Note: Values presented are in nominal ($000s), and numbers may not tie due to rounding.

Table 1

In order to model the SGF Project costs in a manner that most inclusively reflects the cost of the implementation, the economic analysis used the following assumptions:

- Useful life by various asset categories are as provided in Attachment 6 to the accompanying Exhibit;

- Cost estimates are based on preliminary design and include high-level cost assumptions. Estimates may change once final design and engineering is completed and contracts from external parties are confirmed;
- Recovery of costs is assumed as the proposed preferred option as provided in Exhibit G to the accompanying Application;
- Economic analysis and calculation includes the total (not average) deferred SGF Project cost;
- Sales forecast based on February 2016 Power Supply Improvement Plan filing using the low fuel forecast, no conversion to liquefied natural gas, and no modernization of existing units;
- Typical residential customer consumes an average of 500 kWh/month; and
- Financial inputs which were assumed as follows:
    - Discount rate = 8.076%;
    - Federal income tax rate = 32.9% effective;
    - State income tax rate = 6.0% effective;
    - State investment tax credit = 4.0%;
    - Composite revenue tax rate = 8.9%; and
    - Bonus depreciation at 50% through 2017, 40% in 2018, and 30% in 2019

Taking into account the various SGF Project assumptions, including the anticipated timing and estimated levels of offsetting benefits that the Companies expect will be realized in connection with the SGF Project implementation, the Companies produced a simulation of the financial impact to a typical residential customer using 500 kWh per month showing that the impact would be on average $0.23 at Hawaiian Electric, $0.35 at Maui Electric, and $0.20 at Hawai‘i Electric Light. Figure 1 below illustrates the financial impact over the twenty-year life of the investment by company.

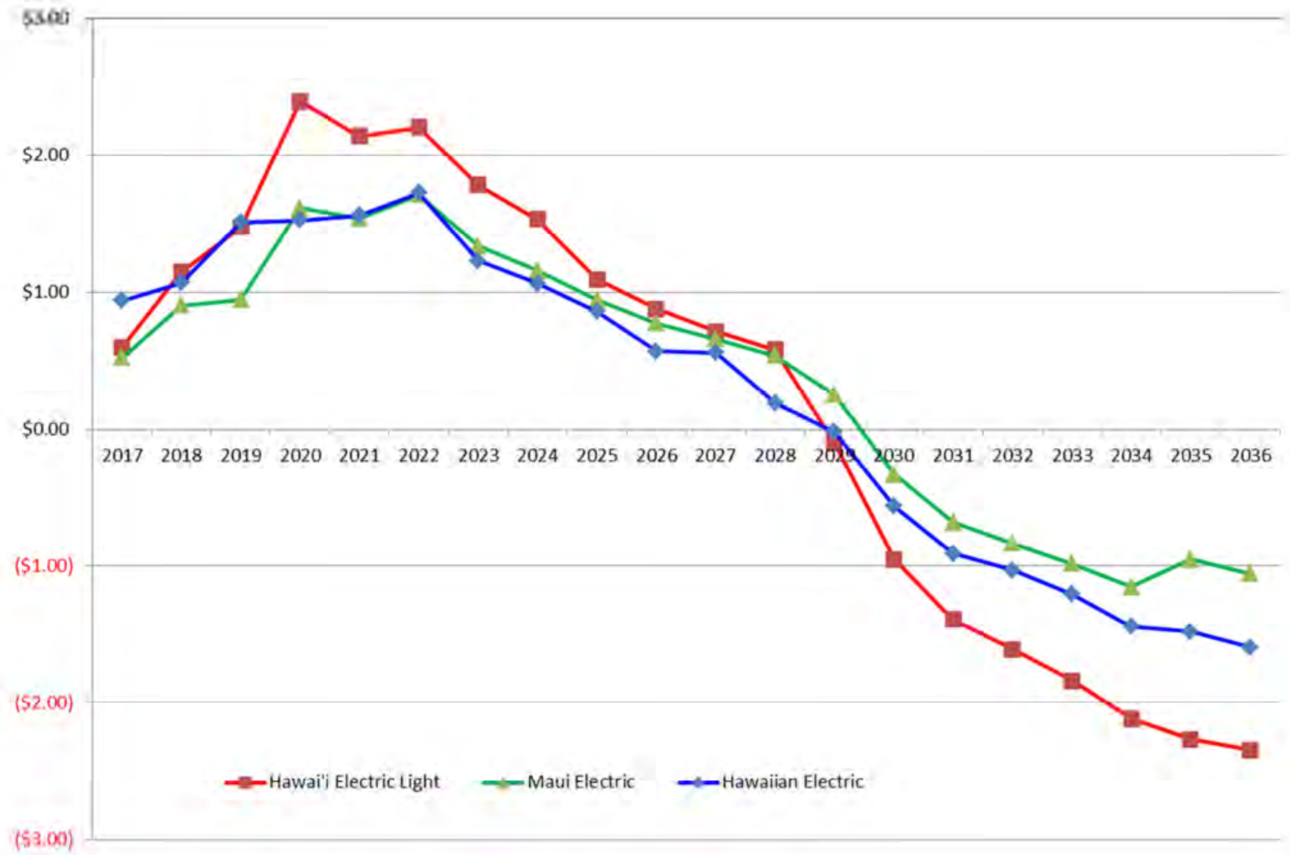

Figure 1

The following data are from the individual company simulated typical residential customer bill analyses:

I. HAWAIIAN ELECTRIC

Inclusion of Hawaiian Electric's share of the SGF Project cost in rate base in 2017 will result in residential customers on O'ahu experiencing a financial impact that will peak in 2022 at $1.73, as shown in Table 2, below. Benefits are realized as early as the first year with overall bill savings starting in 2029. The smooth financial impact is attributable to costs and benefits are shared by a larger pool of customers. Table 2 provides the estimated customer impact by year.

Year	Total Cost	Sales Forecast	Cost per kWh	Average Monthly Financial Impact
2017	12,241,181	6,505,354	0.1882	0.94
2018	14,128,108	6,619,726	0.2134	1.07
2019	20,176,262	6,667,307	0.3026	1.51
2020	20,249,563	6,639,645	0.3050	1.52
2021	20,622,561	6,599,452	0.3125	1.56
2022	22,538,128	6,532,535	0.3450	1.73
2023	15,952,026	6,484,788	0.2460	1.23
2024	13,768,411	6,465,208	0.2130	1.06
2025	11,052,141	6,408,757	0.1725	0.86
2026	7,275,725	6,376,824	0.1141	0.57
2027	7,120,900	6,344,210	0.1122	0.56
2028	2,434,018	6,329,250	0.0385	0.19
2029	(242,719)	6,256,520	(0.0039)	(0.02)
2030	(7,012,999)	6,216,751	(0.1128)	(0.56)
2031	(11,290,023)	6,220,292	(0.1815)	(0.91)
2032	(12,985,356)	6,296,324	(0.2062)	(1.03)
2033	(15,261,053)	6,330,129	(0.2411)	(1.21)
2034	(18,440,888)	6,386,995	(0.2887)	(1.44)
2035	(19,092,381)	6,443,810	(0.2963)	(1.48)
2036	(20,805,544)	6,523,777	(0.3189)	(1.59)
			Average	**$0.23**

Table 2

- The 2019 financial impact increase is primarily due to application development capital costs going into service in 2017 and 2018 in the amount of $33 million and $33.5 million, respectively. Further increases are due to expense costs of $2.5 million, or 22% from the prior year. The expenses are from the retirement of old meters which increases from $750,000 to $1.8 million between 2018 and 2019. AMI begins transitioning labor from capital to expense ($800,000 to $1.5 million) and software-as-a-service ("SaaS") expenses increase from $1.3 million to $1.8 million as more meters are installed between Years 2018-19.
- The 2022 financial impact peak is primarily due to expenses increasing by $2.7 million, or 19% from the prior year. There is a conversion from Silver Springs Networks ("SSNI") SaaS costs to On-Premise Managed Hardware/Software which results in an increase in AMI (from $1.9 million to $2.9 million for maintenance fees and from $500,000 to $1.5 million for outside services) and CVR (from $500,000 to $1.3 million) expenses between 2021 and 2022. In addition, there is incremental labor being hired for CVR in 2022 (from $50,000 to $410,000). There was also reduced growth in the internal labor offset benefit which is a benefit that only covers Years 1 to 5 for all three companies.
- The 2023 financial impact decrease is primarily due to expenses decreasing by $3.8 million, or 23% from the prior year. The conversion from SaaS to On-Premise

Managed Hardware/Software results in a dramatic reduction in monthly fees for the SSNI SaaS relative to the prior year.

- The 2026 -2027 financial impact stays flat due to expense costs being $2 million, or 16% higher in 2027 as compared to 2026. This offsets any increase in benefits. These expenses are primarily attributable to AMI cybersecurity network costs.

II. MAUI ELECTRIC

Inclusion of Maui Electric's share of the SGF Project cost in rate base in 2017 will result in residential customers on Maui, Lana‘i, and Moloka‘i experiencing a bill impact that will peak in 2022 at $1.71, as shown in Table 3, below. Benefits are realized as early as the first year with overall bill savings starting in 2030. Table 3 provides the estimated customer impact by year.

Year	Total Cost	Sales	Cost per kWh	Average Monthly Financial Impact
2017	1,172,999	1,116,995	0.1050	0.53
2018	2,055,428	1,137,384	0.1807	0.90
2019	2,170,085	1,147,496	0.1891	0.95
2020	3,734,839	1,156,187	0.3230	1.62
2021	3,568,282	1,159,632	0.3077	1.54
2022	3,988,294	1,165,940	0.3421	1.71
2023	3,142,187	1,177,047	0.2670	1.33
2024	2,755,411	1,190,201	0.2315	1.16
2025	2,263,156	1,198,739	0.1888	0.94
2026	1,869,404	1,207,639	0.1548	0.77
2027	1,595,480	1,208,298	0.1320	0.66
2028	1,300,183	1,202,551	0.1081	0.54
2029	598,041	1,184,130	0.0505	0.25
2030	(774,546)	1,171,454	(0.0661)	(0.33)
2031	(1,585,292)	1,165,422	(0.1360)	(0.68)
2032	(1,958,789)	1,174,189	(0.1668)	(0.83)
2033	(2,358,225)	1,196,255	(0.1971)	(0.99)
2034	(2,819,862)	1,222,360	(0.2307)	(1.15)
2035	(2,368,757)	1,245,454	(0.1902)	(0.95)
2036	(2,682,869)	1,268,654	(0.2115)	(1.06)
			Average	**$0.35**

Table 3

- The 2019 financial impact stays relatively flat from the prior year due to capital and expenses being offset by a large increase in direct customer benefits. The increase in direct customer benefits is for CVR, as this is the first full year of Maui Electric realizing benefits related to this work stream.
- The 2022 financial impact peak is due to expenses increasing by $400,000 or 12% from the prior year. This is due to the conversion from SaaS to On-Premise Managed hardware and software which results in higher expenses. There was also reduced

growth in the internal labor offset benefit which is a benefit that only covers Years 1 to 5 for all three companies.

- The 2035 financial impact increase is due to benefits decreasing slightly from the prior year by $500,000 or -7%.

III. HAWAI'I ELECTRIC LIGHT

Inclusion of Hawai'i Electric Light's share of the SGF Project cost in rate base in 2017 will result in residential customers on Hawai'i experiencing a financial impact that will peak in 2020 at $2.39, as shown in Table 4, below. Benefits are realized as early as the first year with overall bill savings starting in 2029. Table 4 provides the estimated customer impact per year.

Year	Total Cost	Sales	Cost per kWh	Average Monthly Financial Impact
2017	1,201,319	999,637	0.1202	0.60
2018	2,306,909	1,005,643	0.2294	1.15
2019	2,994,439	1,013,881	0.2953	1.48
2020	4,896,221	1,022,952	0.4786	2.39
2021	4,385,633	1,024,249	0.4282	2.14
2022	4,531,857	1,026,712	0.4414	2.21
2023	3,666,205	1,028,915	0.3563	1.78
2024	3,163,240	1,031,100	0.3068	1.53
2025	2,245,427	1,026,451	0.2188	1.09
2026	1,793,910	1,022,633	0.1754	0.88
2027	1,448,482	1,014,957	0.1427	0.71
2028	1,175,340	1,007,190	0.1167	0.58
2029	(196,455)	989,564	(0.0199)	(0.10)
2030	(1,873,515)	983,232	(0.1905)	(0.95)
2031	(2,739,913)	983,960	(0.2785)	(1.39)
2032	(3,172,027)	986,123	(0.3217)	(1.61)
2033	(3,638,880)	989,122	(0.3679)	(1.84)
2034	(4,236,833)	1,000,462	(0.4235)	(2.12)
2035	(4,592,982)	1,012,234	(0.4537)	(2.27)
2036	(4,822,241)	1,027,392	(0.4694)	(2.35)
			Average	**$0.20**

Table 4

- The 2020 financial impact peak is due to expenses increasing by $1 million, or 37% from the prior year, and capital costs of $15 million and $19 million in 2018 and 2019, respectively, starting to depreciate.
- The 2022 expenses increased by $200,000 or 6% from the prior year, creating a peak while benefits remained flat from the prior year. This was due to reduced growth in the internal labor offset benefit which is a benefit that only covers Years 1 to 5.

- The 2029 – 2030 financial impact sharply decreases due to a decrease in expenses of 14% and 34%, respectively. This decrease is due to the costs related to the retirement of old meters costs decreasing by $500,000 and $1.5 million, respectively

Exhibit C

Smart Grid Foundation Project

Customer Engagement Activities

CUSTOMER ENGAGEMENT ACTIVITIES

The customer engagement activities carried out in connection with the Hawaiian Electric Companies'[1] Initial Phase demonstration project ("Initial Phase") indicate that in order to be successful, the implementation component of the Companies' Smart Grid Foundation Project ("SGF Project") will require a proactive, targeted, collaborative, responsive and flexible communications effort to educate and engage with customers throughout the implementation. Consistent with the results of prior Smart Grid implementations at other utilities, the lessons learned from the Companies' Initial Phase revealed that engaging customers early and often provides customers with more opportunities to learn about the benefits of Smart Grid technologies and allows them to make more informed decisions.

The same general customer engagement principles that were applied in the Initial Phase will be applied to the SGF Project, with a focus on helping customers reduce their electricity usage, improve safety and service reliability, and support Hawai'i's clean energy transformation. As the SGF Project progresses, the Companies intend to continue engaging customers through community outreach, customer education, government relations, third-party engagement, media relations, customer research, employee engagement and customer service support.

I. APPROACH TO SMART GRID CUSTOMER ENGAGEMENT

In preparing for the SGF Project, the Companies have improved upon their Initial Phase Smart Grid customer engagement plan to educate customers about the installation process for smart meters, their supporting infrastructure and associated benefits of a Smart Grid in Hawai'i. This refined plan, which was based in part on lessons learned from Smart Grid implementations at other utilities coupled with the Companies' Initial Phase project, was designed to be modular and adaptable to fit the specific needs of the diverse communities and customers that the Companies serve.

While the customer engagement plan was developed specifically for the Initial Phase, the same principles will apply during the SGF Project. Moving forward, as the SGF Project expands further through the Companies' service territories, ongoing assessments of the results of the Companies' customer engagement efforts will enable the Companies to further update their customer engagement plan.

A. SMART GRID IMPLEMENTATIONS AT OTHER UTILITIES

In recent years, Smart Grid projects have been implemented at many utilities nationwide. Prior to commencement of the Initial Phase, the Companies studied many of these implementations to learn from prior experiences. Specifically, the Companies reviewed the following pilots/utilities' implementations and accompanying customer engagement plans:

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[1] The "Hawaiian Electric Companies" or "Companies" are Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Maui Electric Company, Limited ("Maui Electric") and Hawaii Electric Light Company, Inc. ("Hawai'i Electric Light").

- Maui Smart Grid pilot program;
- Kaua‘i Island Utility Cooperative;
- Florida Power & Light Company;
- Pacific Gas and Electric Company;
- Sacramento Municipal Utility District;
- Oklahoma Gas & Electric;
- Commonwealth Edison; and
- American Electric Power.

Additionally, the Companies have established a collaborative relationship with their strategic partner, Silver Spring Networks (“SSNI”), who has shared the experience it has gained through working on customer engagement programs with other utility clients. It is readily apparent from prior Smart Grid implementations that effective customer engagement is critical to a successful project, as Smart Grids introduce customers to new technologies, new options and additional information about their energy use. Some of the key takeaways from prior Smart Grid implementations that will be applied throughout the Companies’ Smart Grid customer engagement include:

- The importance of engaging customers early and often, as early engagement consistently resulted in higher rates of customer acceptance;

- Smart Grid initiatives need to be treated as customer projects rather than infrastructure projects;

- A higher level of customer engagement is necessary, as Smart Grid solutions offer customers more options and more information about their energy usage;

- Customers should be informed of upcoming implementation plans in a timely manner so that they have more opportunity to learn about the benefits of Smart Grid technologies;

- Customer concerns must be addressed; and

- Customers should be provided the option to enroll in the Companies’ proposed Non-Standard Meter (“NSM”) Tariff program.[2]

The Companies’ review of prior Smart Grid projects confirms that some customers will not engage regardless of the Companies’ engagement efforts and some will chose not to participate in the SGF Project due to various customer concerns. The Companies’ customer engagement plan takes into account the fact that customers must be provided with substantial information in order to support an informed decision.

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[2] See Exhibit H to the accompanying Application, which is a proposed NSM Tariff that would enable customers to opt-out of Smart Grid services with the payment of a non-standard meter enrollment fee and recurring monthly service fee.

B. ENGAGEMENT PRINCIPLES

Smart Grid is a key component of the Companies' clean energy transformation.[3] As such, it is important to engage customers and help them understand how Smart Grid development will help the Companies achieve key goals for 2030, which include:

- Increasing the use of renewable energy to 65% and achieving a 100% renewable portfolio standards goal by 2045;[4]
- Lowering customer bills by 20%;
- Tripling the amount of distributed energy resources; and
- Expanding customer options.

The following set of fundamental communication guidelines were developed to engage customers and other stakeholders regarding the Companies' Smart Grid, and subsequently will be utilized throughout the SGF Project:

- *Proactive*: Anticipate customer and stakeholder needs and develop approaches to meet those needs;

- *Targeted/Localized*: Set realistic expectations about what tools and functionality will be available to each segment of customers, setting realistic timelines for each step of the way;

- *Collaborative*: Work with customers and stakeholders to improve the experience, products and services they receive through ongoing engagement;

- *Responsive*: Respond promptly and transparently to all inquiries; and

- *Flexible*: Expect and accommodate continual process and communication improvements.

C. EDUCATING CUSTOMERS ABOUT SMART GRID

Throughout the SGF Project, the Companies will focus on educating customers on the benefits of Smart Grid, particularly in three areas:

(1) Providing customers with more information about their energy usage to help them better manage their electricity bills;

(2) Making electric service safer and more reliable; and

---

[3] See Applicants' Response to AES-IR-7 filed in Docket No. 2015-0022.

[4] Section 269-92 of the Hawaiʻi Revised Statutes requires each electric utility company that sells electricity for consumption in the State to establish an RPS of 100% of its net electricity sales by December 31, 2045.

(3) Modernizing the grid as part of the State's clean energy transformation.

The Companies will be providing information in easy to understand language, while leveraging visuals and other multi-media capabilities to promote understanding. Educational outreach will also focus on helping customers understand how this implementation is a building block to many of the future customer options intended by the State's clean energy transformation, and how each customer can play a part in moving the Companies forward.

II. CUSTOMER ENGAGEMENT DETAILS

The Companies' Smart Grid customer engagement activities employ a variety of multi-channel engagement tools and tactics, including: (1) community outreach; (2) customer education; (3) government relations; (4) third-party engagement; (5) media relations; (6) customer research (and measurement); (7) employee engagement; and (8) customer service support. The following sections describe the tactics and activities in each category, and also detail how those activities may be adapted throughout the SGF Project to fit the interests and needs of different customers and communities.

A. COMMUNITY OUTREACH, COLLABORATION AND FEEDBACK

One of the most effective means of outreach is to engage with communities directly affected by Smart Grid in meaningful, open discussions through the mail, and through personal and group interactions. Throughout the SGF Project, these interactions will provide opportunities to better understand customers' concerns and respond to them directly. It is essential to engage with customers prior to the installation of smart meters and the Smart Grid infrastructure, as providing customers with information early and often allows them to make more informed decisions. The Companies will continue to develop information to address the differing needs and interests of residential and commercial customers throughout their Smart Grid.

As further discussed below, the major components of the outreach model are: (1) direct mail; (2) door-to-door canvassing; (3) open houses; (4) stakeholder meetings and demonstrations; and (5) communication platforms to share information and provide the Companies with feedback (such as social media).

1. Direct Mail

Direct mail is an effective means of reaching specific groups of customers. The Companies will continue to develop direct mail content that will be used to explain the Smart Grid and its implementation. Direct mail will also be used to educate customers on Smart Grid technology and direct them to other resources where they could gather more information (such as contacting a Company representative and finding information online). Following the SGF Project's rollout schedule, every customer will receive a notification in the mail informing them of the program and the anticipated benefits of Hawai‘i's Smart Grid. Customers will also receive notifications informing them of the meter installation schedule, as well as educational brochures that explain how to use the online customer energy portal to monitor their energy usage.

2. Door-to-Door Canvassing

Following after the direct mail-outs, subsequent door-to-door canvassing may be executed in selected residential neighborhoods. This method of customer outreach will only be utilized in areas that are conducive to its execution and where such targeted efforts will reap a positive customer experience. This is primarily because certain neighborhoods might not allow for such contact (e.g., gated communities, apartment complexes). Moreover, canvassing is a resource-intensive activity with significant manpower requirements and costs. It must therefore be continually evaluated for practicality and potential effectiveness.

There are clear benefits in conducting such manpower intensive outreach, as it will provide customers with additional information and a personal opportunity to ask questions. These personal conversations will allow questions to be answered, and feedback and further questions to be gathered. Customers may also be invited to attend open house meetings in their neighborhoods, call the Companies with questions and access additional information on the Companies' website.

3. Open Houses

The Companies may offer open house meetings in the community prior to the installation of smart meters and the Smart Grid infrastructure. At these open houses, customers will have the opportunity to meet face to face with employees, gather detailed information about Smart Grid, learn more about the benefits of Smart Grid, as well as the useful features of their online customer energy portal. It is also during these sessions that the Companies will invite third-party experts who will be able to address various potential customer concerns. The open house sessions will allow for comfortable environments for customers to meet with representatives from the Companies and trusted third-party organizations.

4. Stakeholder Meetings and Demonstrations

Meetings with key stakeholder groups are an established practice for engaging with communities. Such meetings provide an opportunity for stakeholders to learn more about topics and issues of interest to their communities and constituents. The Companies will hold meetings with key stakeholder groups within the SGF Project's communities, providing presentations that will explain the benefits of Smart Grid technologies, as well as giving customers more opportunities to ask questions and address concerns. Efforts will be made to identify appropriate stakeholder groups, and to schedule meetings at locations and times that offer customers convenient opportunities to learn more about the Companies' Smart Grid. Some of the demonstrations will be scheduled to occur in special venues (e.g., shopping malls) to provide insight and hands-on opportunities to interact with new Smart Grid technologies like the online customer energy portal.

5. Communication Platforms to Share Information and Provide the Companies with Feedback

The Companies will be providing outreach and information to customers through social media campaigns, such as Facebook, Twitter and Instagram. In addition, the Companies will continue to provide customers with various platforms to gain more information at each step during the implementation process, including access to a phone number dedicated to answering questions about Smart Grid, and dedicated web/mobile contact capabilities through the Companies' dedicated Smart Grid website.

B. CUSTOMER EDUCATION

The Companies will leverage and update educational materials created during the Initial Phase to help customers better understand the many components of Smart Grid and the benefits they enable. These materials, which are designed to be consistent with the Companies' engagement principles, include:

- Brochures;
- Frequently Asked Questions ("FAQs");
- Website content;
- Educational content in customer newsletters and other communication vehicles produced by the Companies;
- Fact sheets; and
- Online customer energy portal training materials.

These materials will be provided to customers through a variety of delivery mechanisms, including direct mail, the Companies' website, hand-delivery during canvassing, in-person at community meetings, and by mail upon request when customers contact the Companies with questions.

These materials will also be refined to reflect feedback from customers provided throughout the implementation. This is expected as part of the on-going process to continuously improve customer engagement and prevent the information from becoming stale. Education methods and opportunities will change over time. For example, at the time the Initial Phase started, the Companies were just launching their social media platforms and therefore, they were not used as an education engagement channel. This channel is now developed and will be used as another method to further engage and educate customers about the benefits of Smart Grid technologies. Additional materials will be developed to appropriately reflect the online/mobile customer experience.

Due to the larger scope of the SGF Project, targeted advertising will serve as an effective means of educating customers about Smart Grid and providing them with pathways to gain more information. Such advertising will take a targeted approach to inform customers about benefits available to them, such as using the online customer energy portal to learn more about their energy usage. Any advertising will likely include a limited use of mass media combined with targeted community-based media, such as community newspapers, ethnic press and online media, as well as customer testimonials.

C. GOVERNMENT RELATIONS

Elected officials, government agencies and regulators are key stakeholders in the community who represent the interests of both their specific constituencies and the general public. Therefore, it is important to keep them informed about the Companies' Smart Grid so that they may address any questions or concerns which may arise. The Companies plan to conduct briefings for government stakeholders before embarking on community outreach efforts, while maintaining reasonably timed periodic update briefings over the course of the implementation.

The Companies have found that briefings with government agencies and regulators (e.g., the Commission, the Consumer Advocate and the Department of Business, Economic Development, and Tourism) generate valuable feedback which helps to refine the Companies' customer engagement plans. Further, it provides the opportunity to also supply government representatives with educational materials developed for use with customers.

D. THIRD-PARTY ENGAGEMENT

Prior to installation of any Smart Grid technology, the Companies will engage with other key organizations interested in energy issues in Hawai‘i. These early discussions help foster a productive dialogue about the role Smart Grid technology will play in building a cleaner, more secure and more affordable energy future for Hawai‘i. These organizations contribute valuable feedback that helps the Companies to refine the customer engagement plan and to engage in collaborative ways that are beneficial for our communities.

These types of engagements with third-party organizations help the Companies to:

- Build trust and transparency while engaging and educating key stakeholders;
- Identify customers' issues and concerns and define key messages for customer engagement;
- Promote awareness of Smart Grid benefits with trusted third-party voices;
- Anticipate and better address engagement challenges; and
- Provide customers with more cohesive and comprehensive Smart Grid information and options.

These relationships will be productive and the Companies intend to continue their engagement with third-party organizations throughout the SGF Project implementation. The Companies will also be seeking out additional third parties to build similar relationships in order to better anticipate the needs of the diverse customer base and respond to any concerns that may arise.

E. MEDIA RELATIONS

Communicating effectively with customers will require the Companies to effectively engage with the news media. Newspapers, television, radio and online media outlets reach customers across the State and provide opportunities to communicate with a wide audience. To accomplish this, the media will need to have access to information that is accurate and timely, and which addresses the Companies' SGF Project implementation and overall purpose of the Smart Grid. These activities are planned throughout the SGF Project's implementation so that the media is kept current as to the progress of the Companies' Smart Grid.

Hawai'i's communities are served by a diverse array of media organizations, ranging from community newspapers to online blogs and from radio to statewide television broadcasts. The Companies recognize the importance of the different audiences each media outlet serves. The role of the Companies in this process is to enable the media to provide information and coverage that is meaningful to their audiences.

Media relations will continue to be a key activity throughout the SGF Project. Proactively issuing news releases will help keep the public informed of the implementation and its progress. By working with the news media and effectively responding to inquiries, the Companies aim to further educate the public about the benefits of Smart Grid solutions and address any concerns that may arise.

F. CUSTOMER RESEARCH

In order to provide meaningful customer engagement, the Companies need to understand who their customers are, what they need, when they need it and why. Customer research will be utilized in order to target, understand, and measure the effectiveness of the engagement activities and tools. Gathering feedback from customers will help to refine the customer engagement plans and better understand customer interests and concerns. Prior to the start of the community outreach efforts, the Companies will leverage lessons learned from the Initial Phase, and further test various messages and materials with the specific residential and commercial customers. This will help to determine specific groupings of customers' overall level of awareness of Smart Grid technologies, and to identify opportunities for effective engagement and barriers to acceptance. The Companies will also conduct on-going evaluation of the implementation processes, similar to those utilized during the Initial Phase.[5]

Customer behavior, attitudes and opinions will change over time and therefore, will continue to be assessed as the Companies proceed through the SGF Project. It will be important to make continuous efforts to improve the customer engagement plans, proactively identify customer concerns, and evaluate the effectiveness of the Companies' Smart Grid, including but

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[5] See the *Smart Grid Initial Phase Process Evaluation* report developed by Ward Research, Inc., dated May 2015, provided as Attachment 1.

not limited to awareness and understanding of deployment activities and capabilities of the online customer energy portal.

G. EMPLOYEE ENGAGEMENT

The Companies' employees are some of the most important partners in the Smart Grid, as they regularly share information about the Companies' projects with their friends, families and neighbors. Accordingly, the Companies have developed a process to prepare employees to answer questions and communicate the benefits of the Smart Grid.

Information sessions will be held for employees who live within the various deployment areas. The Companies will also hold open house sessions for employees at power plants, facilities and base yards across their service territories. These sessions will provide employees with opportunities to learn more about the Smart Grid. Additional information will be provided to employees through the Companies' standard employee communication channels, such as email, bulletin boards, available training materials and intranet, as well as through specific employee training sessions.

It will be important to keep employees informed and equipped with the appropriate tools and materials so they may continue to answer questions from their friends and neighbors, and discuss the program with the communities that the Companies serve.

H. CUSTOMER SERVICE SUPPORT

Many of the Companies' employees work in customer-facing roles and interact with customers as a normal part of their jobs. The Companies will develop materials and tools to help prepare these employees to respond to questions from customers about the Smart Grid. For example, the Companies will provide training for line crews and other employees who are frequently approached by customers in the field. Moreover, the Companies have worked with their customer service departments to develop training materials and frequently asked questions ("FAQs") documents to help employees more effectively respond to inquiries. These FAQs will include information specific to addressing the key features of smart meters, setting expectations for timing and functionality, and addressing top concerns that customers have expressed both in Hawaiʻi and elsewhere. Processes have also been developed to escalate inquiries to address customer concerns, and these processes will be continually modified to reflect any unexpected changes that arise during the Companies' SGF Project. In addition, the Companies will create a dedicated hotline for customers to obtain answers to their questions specific to the SGF Project, including information about coordinating installations, customer concerns and opt-out requests. The Companies will continue to support customer-facing departments and employees throughout the SGF Project implementation.

III. CONCLUSION

The customer engagement work carried out in connection with the Initial Phase of the Companies' Smart Grid utilized a proactive, collaborative, responsive and flexible approach to educating customers about the installation process for smart meters, supporting infrastructure and benefits of a Smart Grid. The experiences from the Initial Phase confirm many of the lessons learned from prior implementations at other utilities. Namely, having a customer-focused project in which customers are engaged early and often is essential to a successful Smart Grid implementation.

The takeaways from the Initial Phase are being adapted and applied in the Companies' larger-scale SGF Project, and beyond. Customer acceptance will play a pivotal role in this key element of Hawaiʻi's energy future. As the SGF Project efforts expand across different communities, the Companies will apply the appropriate communication tools and activities (e.g., community outreach, customer education, third-party engagement) to most effectively reach out to its customers.

Attachment 1

Smart Grid Foundation Project

Exhibit C

Smart Grid Initial Phase Process Evaluation

WARD RESEARCH
INCORPORATED

SMART GRID INITIAL PHASE PROCESS EVALUATION

Prepared for:

Hawaiian Electric Company

May 2015

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EXECUTIVE SUMMARY

TELEPHONE SURVEY AMONG RESIDENTIAL AND COMMERCIAL CUSTOMERS

- Based on the survey responses, Hawaiian Electric provided sufficient information to customers regarding the SmartMeter installation at their home or business. Majorities of customers---residential or commercial---recalled receiving a letter from Hawaiian Electric regarding the SmartMeter installation and, from the letter, reportedly understood very or somewhat well what was going to happen with their meter.

	Residential	Commercial
Recall receiving a letter from Hawaiian Electric about SmartMeter installations	82%	63%
(IF READ/GLANCED THROUGH THE LETTER) Understood "very" or "somewhat" well what was going to happen with the meter	79%	82%

- Hawaiian Electric also provided sufficient notice to customers regarding the meter change, based on responses. Although the recall of the postcard about the visit to change the meters was not as wide as was that for the letter, majorities of customers expressed satisfaction (very or somewhat) with the advance notice they did receive from Hawaiian Electric.

	Residential	Commercial
Recall receiving a postcard, telling them that someone would be coming by to change meter	63%	48%
Satisfaction with the advance notice regarding the visit to change meter	75%	75%

- Awareness of the community open house to present info about the idea of a SmartMeter was fairly low and attendance even lower, especially among commercial customers. The open house held some appeal for residential customers, however, with two in five of those aware but unable to attend indicating that they would have attended if they had been able.

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	Residential	Commercial
Recall community open house invitation	23%	8%
(IF AWARE OF COMMUNITY OPEN HOUSE) Attended open house	9%	0%
(IF DID NOT ATTEND) Wanted to attend	42%	25%

- As for the actual visit, large proportions of those who were present during the visit said that they were very or somewhat satisfied, indicating that the person who visited to change the meter was courteous and professional. Large proportions also indicated that the person was knowledgeable about the meters.

	Residential	Commercial
(IF PRESENT DURING THE VISIT) "Very" or "somewhat" satisfied with the visit to change the meter	92%	81%

- Awareness of the "My Energy Use" web portal has room to improve, as does usage among those who were aware, especially since majorities of those residential customers who have logged on to the portal found it very or somewhat useful and some have reportedly used the information in the portal to reduce their electricity use.

	Residential	Commercial
Aware of "My Energy Use" website	36%	25%
Logged on to "My Energy Use"	9%	6%
(IF LOGGED ON) Found "My Energy Use" "very" or "somewhat" useful	74%	33%
(IF LOGGED ON) Used "My Energy Use" information to try to reduce electricity use	37%	33%

ONE-ON-ONE INTERVIEWS WITH INVOLVED EMPLOYEES AND EXTERNAL PARTNERS

The Smart Grid Initial Phase was felt to be a success by the employees and external partners interviewed for the evaluation. The Customer Engagement Process worked very well, according to interview participants, leading to low deferral rates, lack of public controversy, and generally positive (and limited) media coverage. The partnership with community organizations was also felt to be a benefit, as were high levels of employee volunteerism at Hawaiian Electric.

There were some challenges, namely delays caused by problems with the meter inventory and quality control processes. Delays with the web portal and low levels of customer response to the Prepay program were also mentioned. Suggestions for improvement include additional clarity about: a) meter specifications and inventory, b) customer-facing technology, and c) roles at Hawaiian Electric.

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PART I: TELEPHONE SURVEY AMONG SMART GRID INITIAL PHASE RESIDENTIAL CUSTOMERS

OBJECTIVES AND METHODOLOGY

The overall objective of this part of the study was:

TO DETERMINE RESIDENTIAL CUSTOMER SATISFACTION IN THE SMARTMGRID ROLLOUT AREAS AND TO IDENTIFY PROCESS IMPROVEMENTS THAT WILL INCREASE CUSTOMER SATISFACTION, IF NEEDED, IN FUTURE ROLLOUTS.

To meet this objective, a telephone survey was conducted among n=207 residential program participants in the SmartMeter rollout areas. The telephone survey was conducted March 20 to April 6, 2015. Hawaiian Electric provided Ward Research with a database of N=2,982 SmartGrid Initial Phase residential customers. The maximum sampling error is +/- 6.6%.

All interviewing was conducted from the Calling Center in the Ward Research downtown Honolulu office. Upon completion of interviewing, data was processed using SPSS for Windows, a statistical software package.

The survey instrument was designed by Ward Research and submitted to Hawaiian Electric for input and review. A copy of the survey instrument is appended to this report.

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PROFILE OF RESIDENTIAL CUSTOMERS

Ethnicity	**%**
Caucasian	20
Chinese	11
Filipino	6
Hawaiian/part-Hawaiian	16
Japanese	31
Mixed, not Hawaiian	9
Other	6
Refused	1
Age	**%**
18 to 24	1
25 to 34	7
35 to 44	13
45 to 54	15
55 to 64	23
65 or older	42
Gender	**%**
Male	49
Female	51
Base=	**207**

Household Income	**%**
Less than $25,000	9
$25,000 to less than $50,000	13
$50,000 to less than $75,000	17
$75,000 to less than $100,000	17
$100,000 to less than $150,000	13
$150,000 and over	11
Refused	21
Circuit	**%**
Diamond Head	7
Hila 2	16
Kahala	5
Luawai	40
Pearl City 1	6
Pearl City 2	25
Base=	**207**

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Number of People in Household	%
One	22
Two	38
Three or more	39
Refused	1
MEAN	**2.67**
Home Ownership	**%**
Own	65
Rent	34
Occupy without payment	1
Type of Home	**%**
House	67
Apartment	17
Condominium	3
Townhouse	13
Other	1
Base=	**207**

Years Lived in Hawaii	%
Less than 1 year	1
1 to 5 years	5
6 to 10 years	4
11 to 20 years	4
Over 20, not lifetime	25
Lifetime	61
Years Lived at Current Address	**%**
Less than 1 year	5
1 to 5 years	21
6 to 10 years	15
11 to 20 years	19
Over 20, not lifetime	37
Lifetime	2
Refused	1
Base=	**207**

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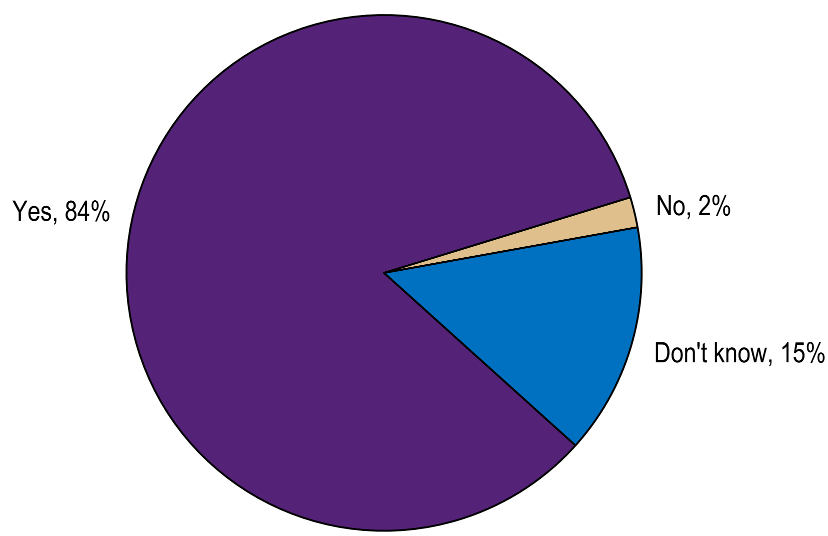
AWARENESS OF SMARTMETER INSTALLATIONS

A large majority of the SmartGrid rollout customers surveyed were aware that a SmartMeter was installed at their home or building (84%).

As far as you know, was your electric meter changed last year and a SmartMeter installed at your home or building?



S3. Recently, Hawaiian Electric has been installing SmartMeters in your neighborhood. As far as you know, was your electric meter changed last year and a SmartMeter installed at your home or building? (Base=207)

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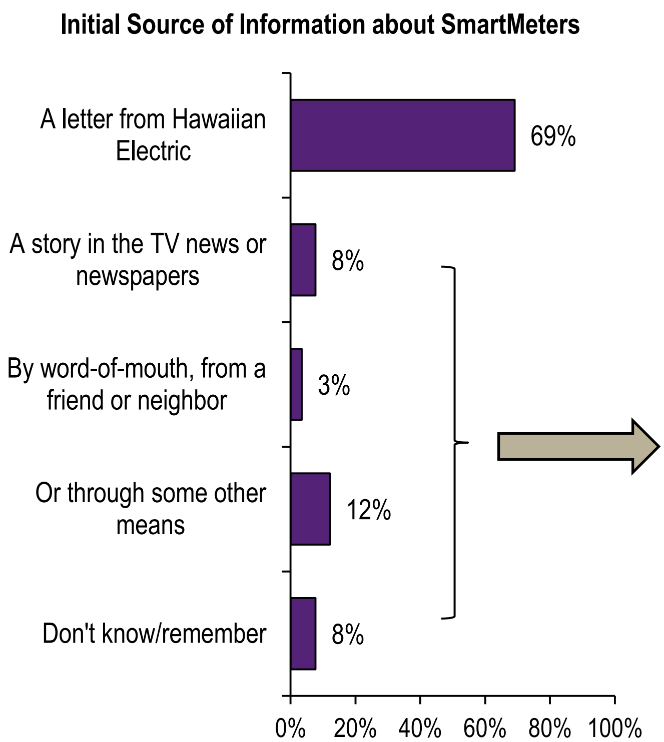
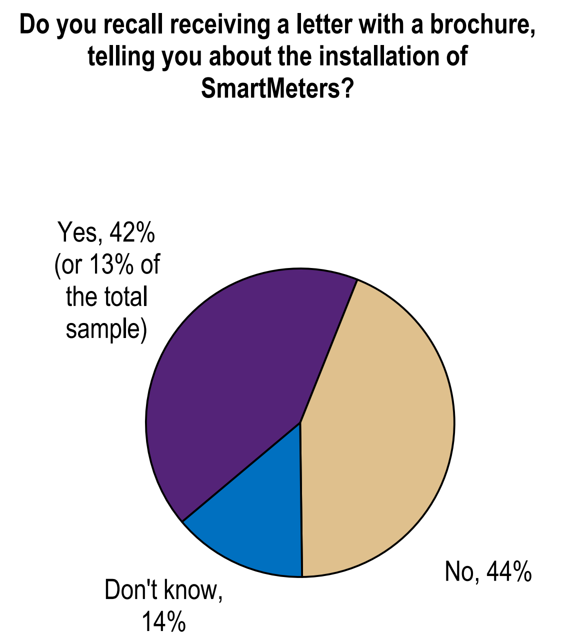
HAWAIIAN ELECTRIC LETTER ABOUT SMARTMETER INSTALLATIONS

Customers were far more likely to have learned about the SmartMeter installations through an introductory letter from Hawaiian Electric than through any other method. Overall, 82% of the customers surveyed could recall receiving a letter from Hawaiian Electric about the SmartMeter installations (69% unaided and 13% aided).



Q1. Please think back to how you first learned about the installation of SmartMeters in your neighborhood? Did you first hear about it through: (Base=207)



Q1a. At some point, do you recall receiving a letter with a brochure, telling you about the installation of SmartMeters in your neighborhood? (Base=64)

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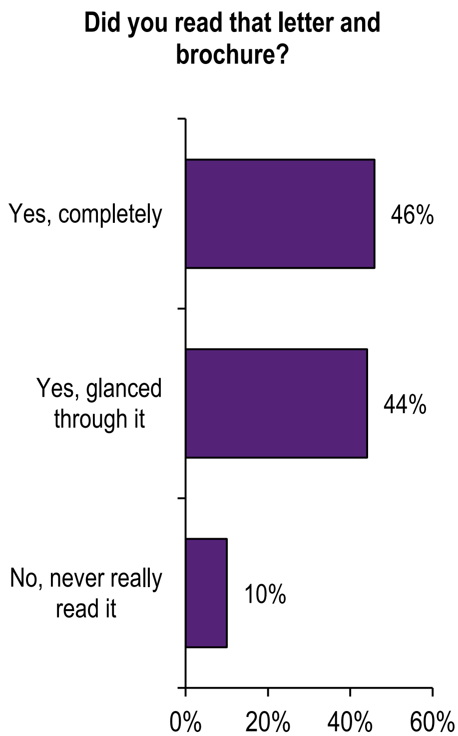
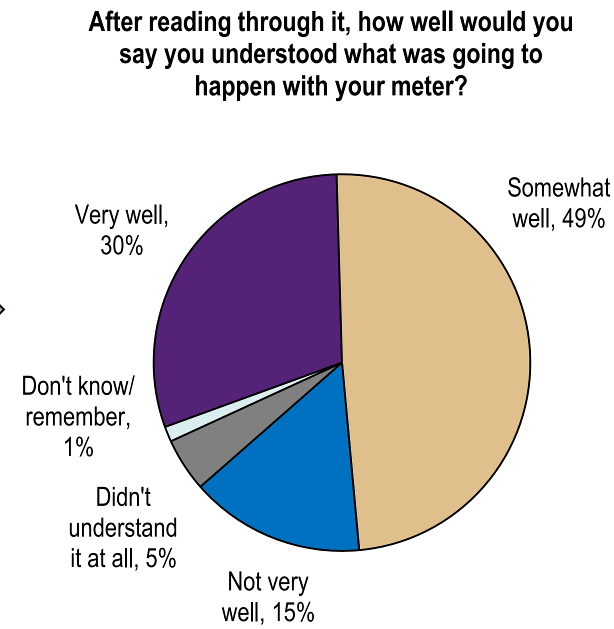
Nine in ten of the customers who received the letter reportedly read it completely (46%) or at least glanced through it (44%). When asked how well, after reading through the letter, they understood what was going to happen with their meter, 79% said "very" or "somewhat well."



Q1b. Please think about that letter and brochure that Hawaiian Electric sent. Did you read that letter and brochure? (Base=170)



Q1c. After reading through it, how well would you say you understood what was going to happen with your meter? Would you say you understood: (Base=153)

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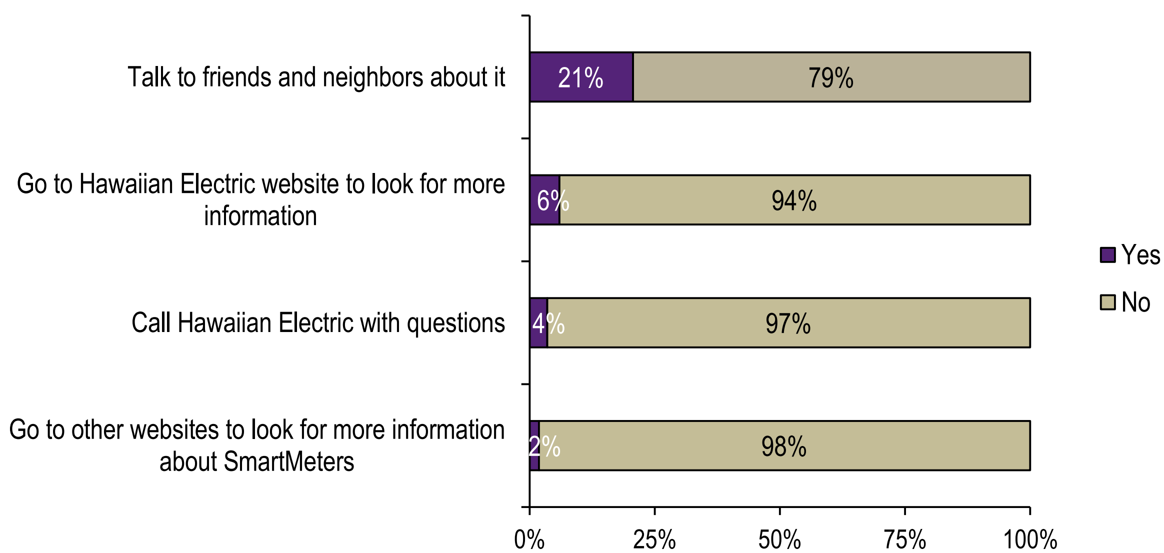
Next, customers were asked if, after receiving the letter, they talked to friends and neighbors about it, went to the Hawaiian Electric website to look for more information, called Hawaiian Electric with questions, or went to other websites to look for more information about SmartMeters. The most often reported reaction to receiving the introductory letter was to talk to friends and neighbors about it (21%).

6% of customers (or n=10) reported going to the Hawaiian Electric website to look for more information. Three out of ten (30%) of those customers felt the website was "very helpful." In contrast, 40% felt the website was not helpful, because it contained the same information as the letter (75%) or because it did not explain how SmartMeters could help customers save electricity (25%).

After receiving the letter, 4% of customers (or n=6) also said they called Hawaiian Electric with questions. Nearly all of those customers felt Hawaiian Electric was "very helpful" (83%) when they called.

And after receiving that letter, what did you do, if anything? Did you:



Q1d. And after receiving that letter, what did you do, if anything? Did you: (Base=170)

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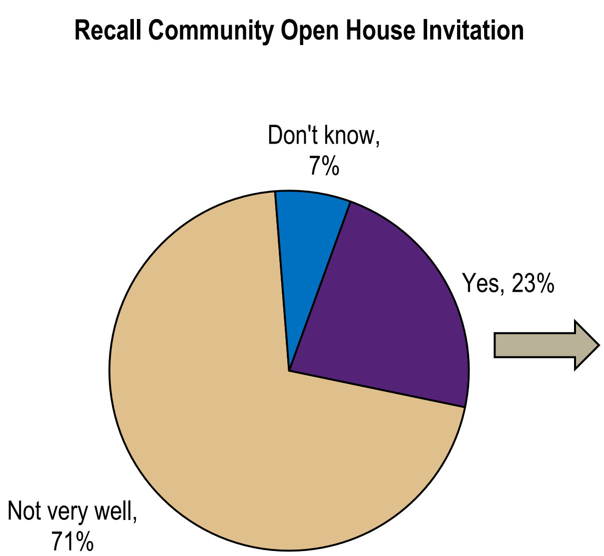
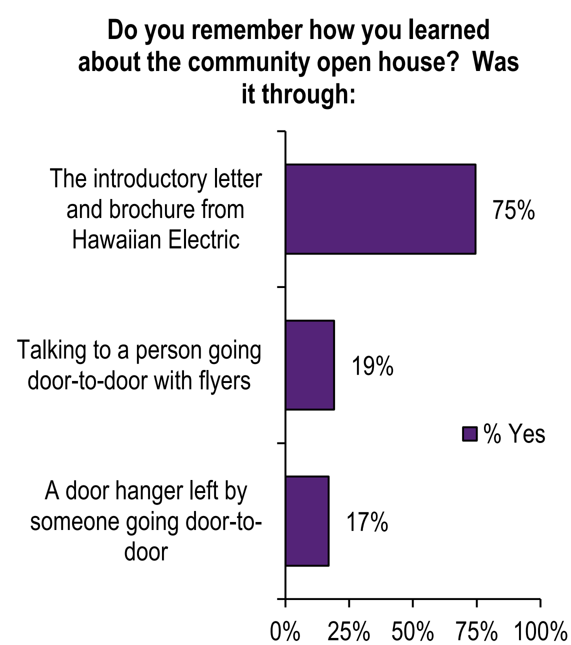
COMMUNITY OPEN HOUSES

More than one-fifth of the customers surveyed could recall a community open house invitation (23%).

Three in four of those customers said they learned about the open houses through the introductory letter from Hawaiian Electric (75%). Another one in five learned about the open houses by talking to a person going door-to-door with flyers (19%).



Q3. Do you recall Hawaiian Electric --- along with its partners Blue Planet Foundation and Hawaii Energy --- inviting you to attend a community open house regarding the installation of the meters? (Base=207)



Q4. Do you remember how you learned about the community open house? Was it through: (Base=47)

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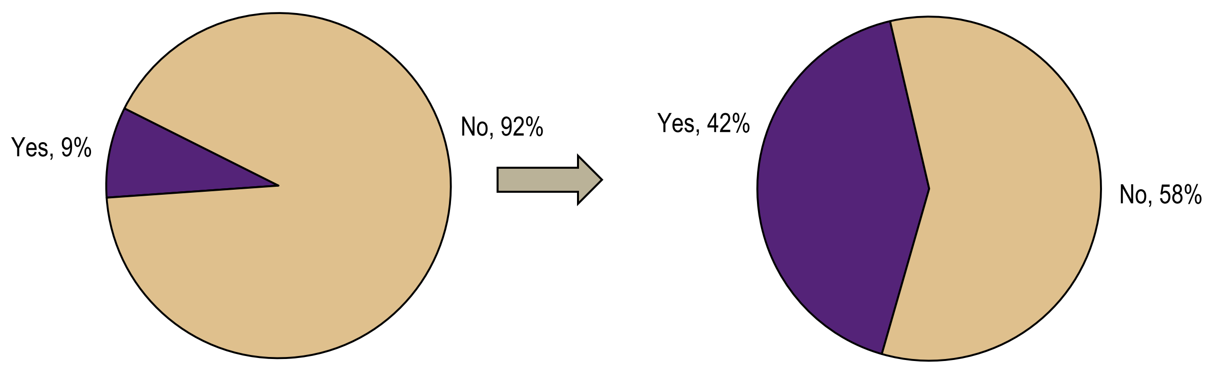
Approximately one in ten of the customers aware of the community open houses reportedly attended an open house (9%) and one in four of these (25%) felt the information shared at the open house was "very helpful." When asked what, if anything, would have made the information more helpful, 50% asked for information on how SmartMeters can help them lower their electric bill.

Among those who didn't attend (92%), two in five reportedly wanted to attend but were unable (42%).

Did you have an opportunity to attend one of these community open houses?

Had you wanted to attend but been unable?



Q6. Did you have an opportunity to attend one of these community open houses? (Base=47)

Q6a. Had you wanted to attend but been unable? (Base=43)

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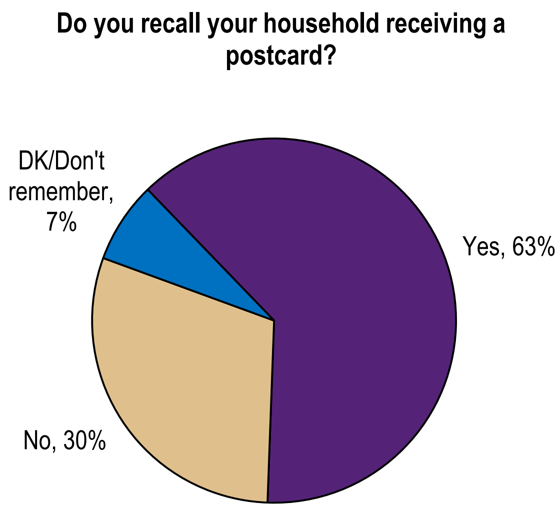
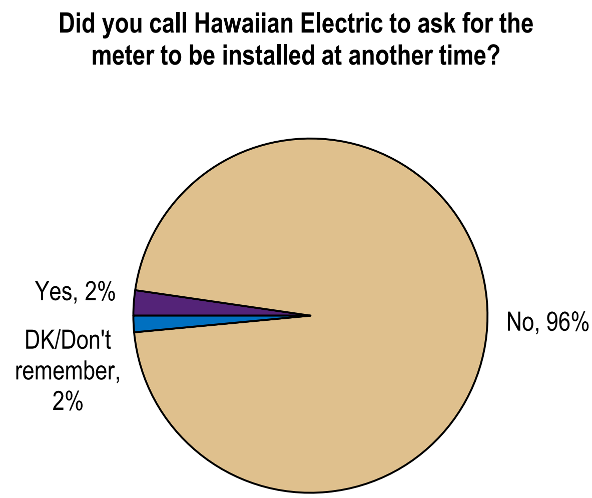
HAWAIIAN ELECTRIC POSTCARD ABOUT THE METER CHANGE

Three in five of the customers surveyed could recall receiving a postcard, telling them that someone would be coming by to change their meter (63%). At that point, 2% said they called Hawaiian Electric to ask for the meter to be installed at another time. 67% said their request was accommodated and 33% could not remember if their request was accommodated.



Q7. Do you recall your household receiving a postcard, telling you that someone would come to change out your meter in the following week or two? (Base=207)



Q8. At that point, did you call Hawaiian Electric to ask for the meter to be installed at another time? (Base=130)

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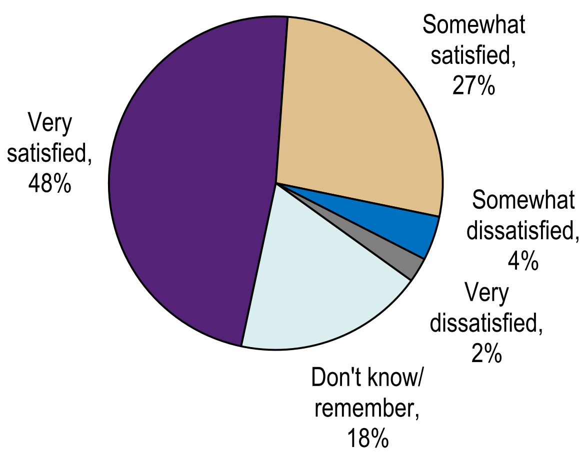
METER CHANGE

Nearly one-half of the customers surveyed reported being "very satisfied" with the advance notice they received regarding their meter change (48%) and 27% said "somewhat satisfied." Dissatisfaction was very low (6%) with 18% unable to recall.

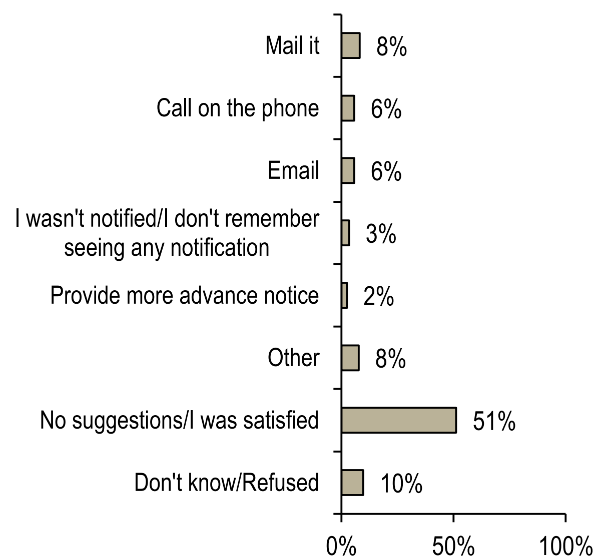
When customers were asked how Hawaiian Electric could improve the notice, one-half indicated that they were satisfied or had no suggestions (51%). Among the suggestions, mailing the notice topped the list (8%), followed by telephone notice (6%) and email notice (6%).

How satisfied were you with the advance notice your household received regarding the visit to change out your meter?



Q9. How satisfied were you with the advance notice your household received regarding the visit to change out your meter? (Base=207)

How could Hawaiian Electric improve the notification to customers regarding the visit to change out the meter? --Top Responses--



Q10. In the future, how could they improve the notification to customers regarding the visit to change out the meter? (Base=207)

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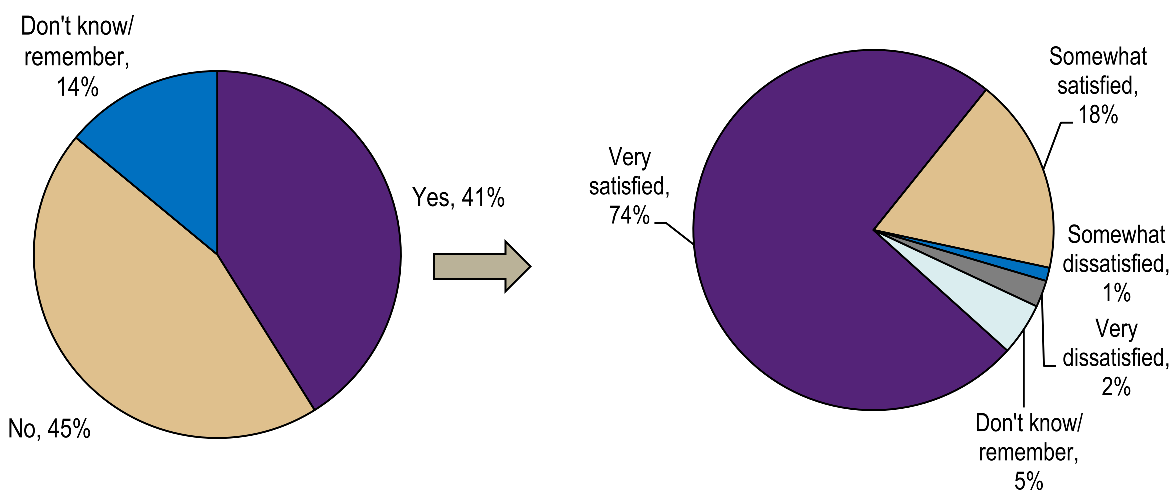
Two in five of the customers surveyed reportedly were home when someone visited to change their meter (41%). Three in four of those customers said they were "very satisfied" with the visit (74%), with another 18% "somewhat satisfied."

Were you (or someone else in your household) home when they came to change your meter?

How satisfied were you with the visit to change your meter?



Q11. Were you (or someone else in your household) home when they came to change your meter? (Base=207)

Q11a. How satisfied were you with the visit to change your meter? (Base=85)

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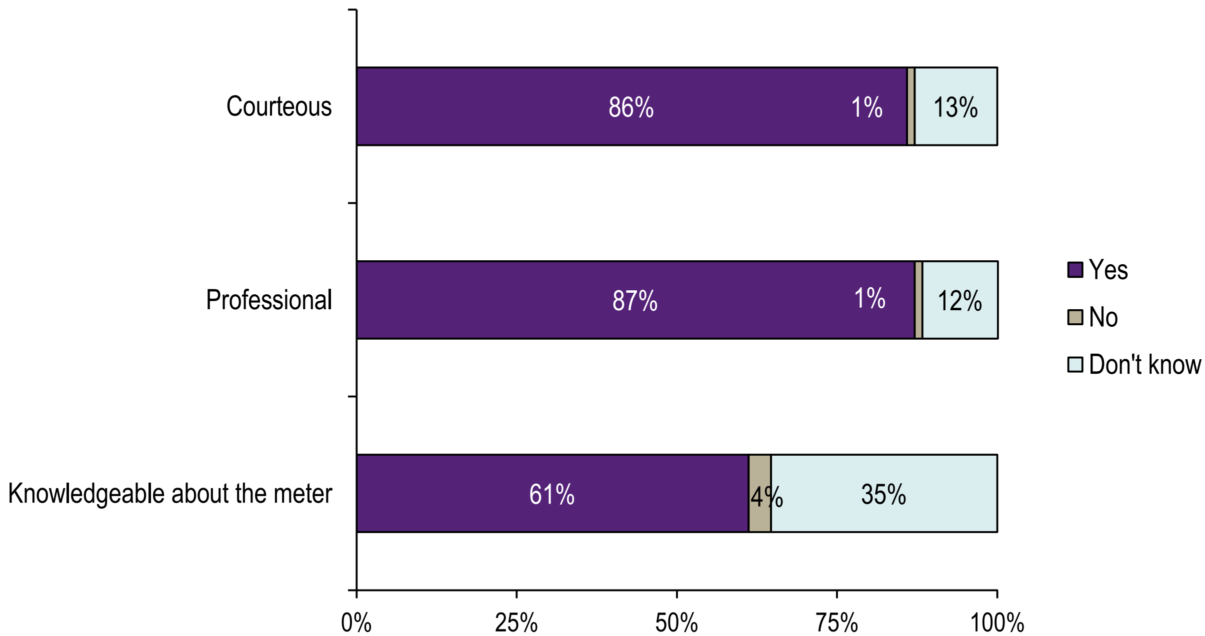
Among the customers who were home, large majorities reported that the person who visited their house to change the meter was professional (87%) and courteous (86%). A majority of customers also said that the person was knowledgeable about the meter (61%; 4% said the person was not knowledgeable and 35% said they did not know).

As far as you can recall, was the person who came to your house:



Q12a. As far as you can recall, was the person who came to your house: (Base=85)

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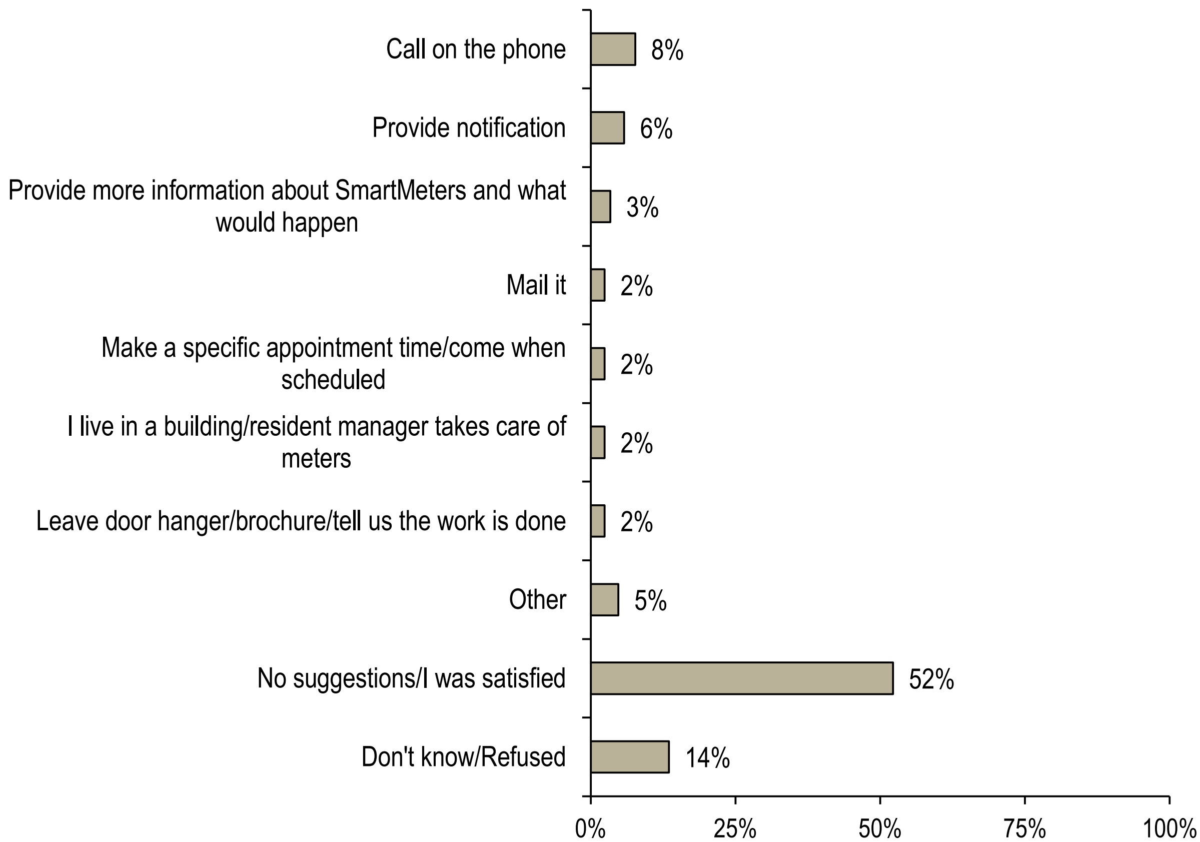
When asked how Hawaiian Electric could improve the visit to customers' homes to change out the meters, a majority had no suggestions or said they were satisfied with the visit (52%). "Call on the phone" topped the list of suggestions (8%), followed by "provide notification" (6%).

Suggestions for Improving the Visit to Customers' Homes
--Top Responses--



Q13. In the future, how could they improve the visit to customers' homes to change out the meters? (Base=207)

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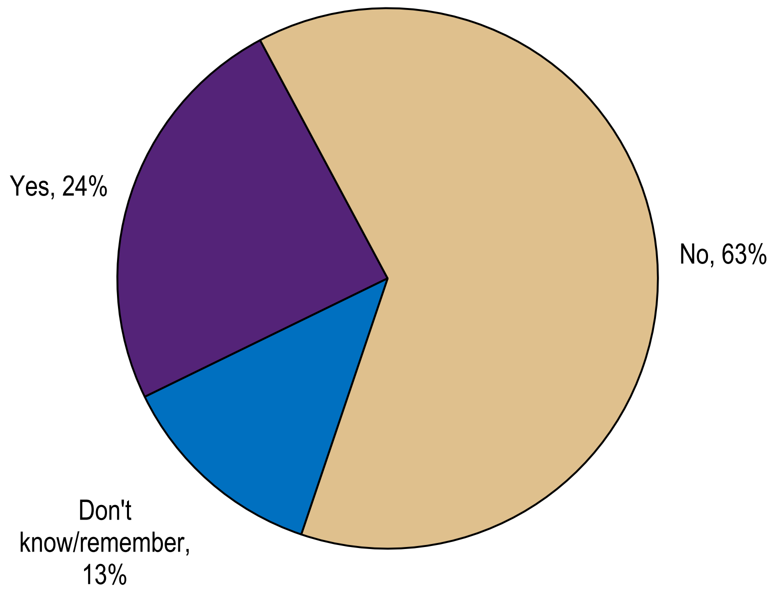
Among the customers who were not home, one in four could recall seeing a door hanger or flyer informing them that someone had been home to change their meter (24%).

Did you or another household member ever see a door hanger or flyer saying that someone had been there to change your meter?



Q14. Did you or another household member ever see a door hanger or flyer saying that someone had been there to change your meter?
(Base=119)

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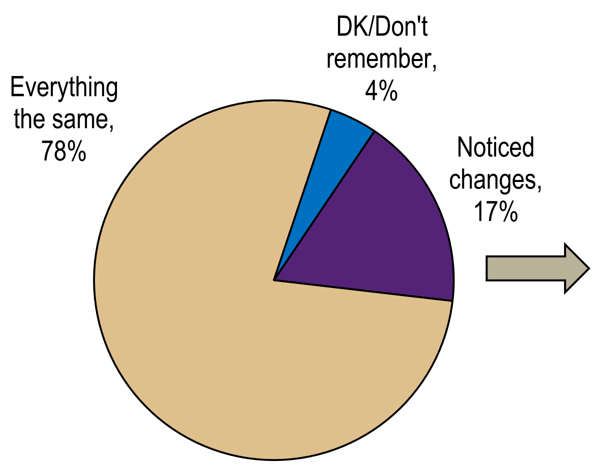
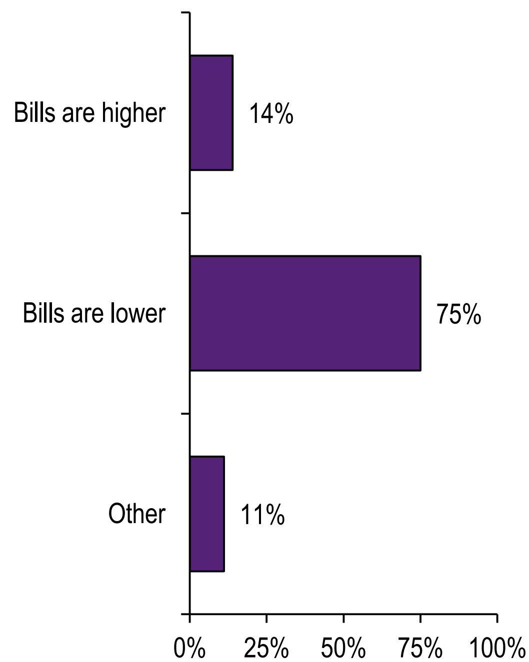
The customers surveyed were also asked if they have noticed any changes since their new meter was installed and 17% said that they have---primarily, that their bills are lower (75%). One out of seven (14%) said they noted higher bills.

Are there any changes you've noticed?



Q15. Since the new meter was installed at your home, are there any changes you've noticed, or is everything really the same? (Base=207)

What changes have you noticed?



Q15a. What changes have you noticed? (Base=36)

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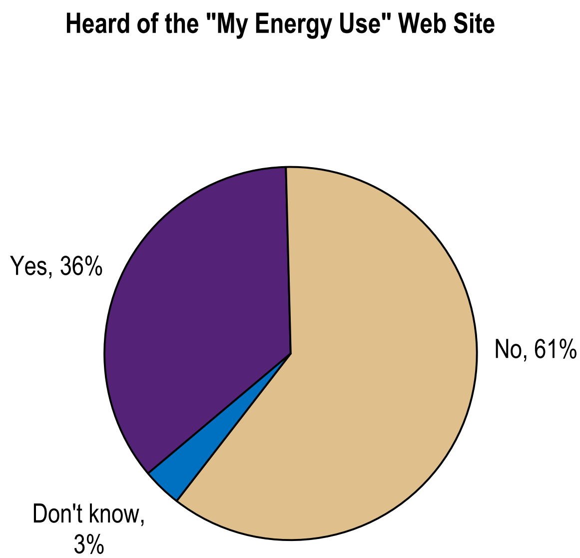
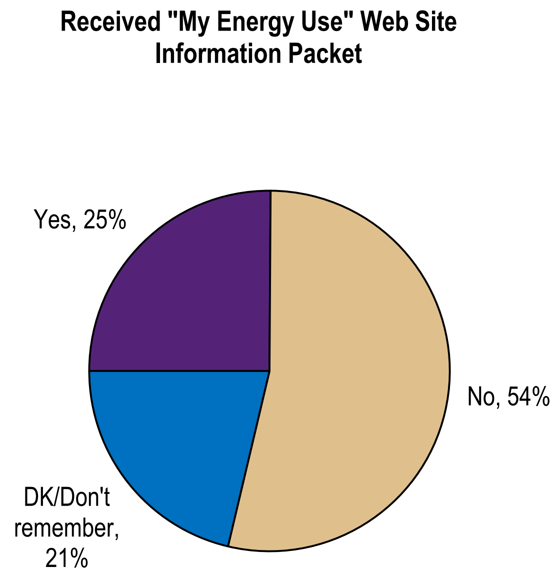
"MY ENERGY USE" WEB PORTAL

More than one-third of the customers surveyed said they had heard of the "My Energy Use" web site (36%), but only one-fourth recalled receiving a "My Energy Use" information packet (25%).



Q16. Have you heard of the "My Energy Use" web site? (Base=207)



Q16a. Have you received a packet of information telling you about "My Energy Use," the website that lets you monitor your energy use? (Base=207)

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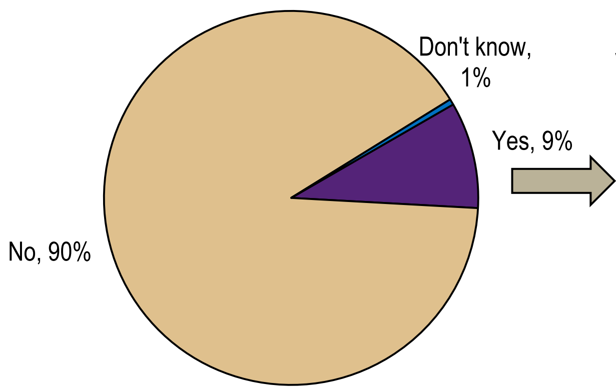
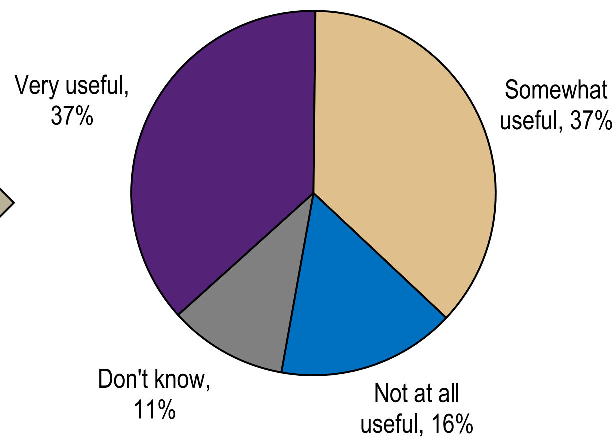
Approximately one in ten customers reportedly had logged on to the “My Energy Use” web portal (9%), while a vast majority had not logged on (90%). More than one-third of the 9% who had logged on called the web portal “very useful” (37%), with another 37% saying it was “somewhat useful” (note that none of the customers said, “not very useful”).

Logged on to the "My Energy Use" Web Portal



Q16b. “My Energy Use” is the Web portal on the Hawaiian Electric website that contains real time information about your household energy use, so you can make decisions about changing behaviors to reduce your usage. Have you logged on to the “My Energy Use” web portal? (Base=207)

Usefulness of "My Energy Use" Web Portal



Q16c. How useful is the “My Energy Use” web portal? (Base=19)

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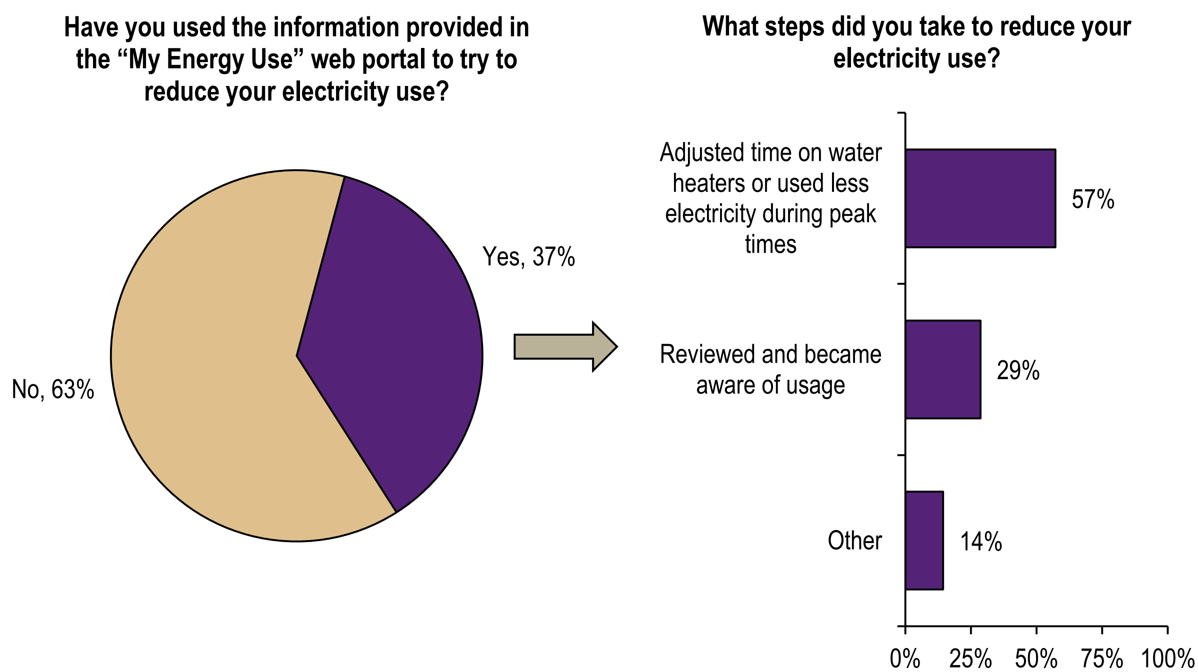
More than one-third of the customers who had logged on to the "My Energy Use" web portal said they had used the information provided to try to reduce their electricity usage (37%), either by adjusting their usage (57%), becoming more aware of their usage (29%), or through other means (14%).



Q16d. Have you used the information provided in the "My Energy Use" web portal to try to reduce your electricity use? (Base=19)

Q16e. What steps did you take to reduce your electricity use? (Base=7)

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PART II: TELEPHONE SURVEY AMONG SMART GRID INITIAL PHASE COMMERCIAL CUSTOMERS

OBJECTIVES AND METHODOLOGY

The overall objective of this part of the study was:

TO DETERMINE COMMERCIAL CUSTOMER SATISFACTION IN THE SMARTGRID PILOT ROLLOUT AREAS AND TO IDENTIFY PROCESS IMPROVEMENTS THAT WILL INCREASE CUSTOMER SATISFACTION, IF NEEDED, IN FUTURE ROLLOUTS.

To meet this objective, a telephone survey was conducted among n=52 commercial entities in the SmartGrid rollout areas. The telephone survey was conducted April 22 to April 27, 2015. Hawaiian Electric provided Ward Research with a database of N=350 Smart Grid Initial Phase commercial customers. The maximum sampling error for a sample this size is +/- 12.5%.

An alert postcard from Hawaiian Electric was sent to customers prior to fielding, alerting them of the study. All interviewing was conducted from the Calling Center in the Ward Research downtown Honolulu office. Upon completion of interviewing, data was processed using SPSS for Windows, a statistical software package.

The survey instrument was designed by Ward Research and submitted to Hawaiian Electric for input and review. Areas of questioning were similar to that from the residential survey, but geared to the commercial market. A copy of the survey instrument is appended to this report.

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PROFILE OF COMMERCIAL CUSTOMERS

Business Type	%
Church	6
Entertainment Venue	6
Hotel	4
Manufacturing Facility	2
Office Building	10
Real estate/Property management	14
Restaurant	4
Retail – Food Store	2
Retail – Non-Food Store	17
Service Provider	29
other	8
Number of Employees	**%**
1-4 employees	62
5-9 employees	17
10-29 employees	10
50-99 employees	4
100 or more employees	6
Don't know/Refused	2
Base=	**52**

2014 Total Business Revenue	%
Under $50,000	8
$50,000 to less than $100,000	12
$100,000 to less than $250,000	14
$250,000 to less than $500,000	12
$500,000 to less than $1 million	12
$1 million to less than $5 million	6
$10 million or more	4
Don't know/Refused	35
Gender	**%**
Male	48
Female	52
Base=	**52**

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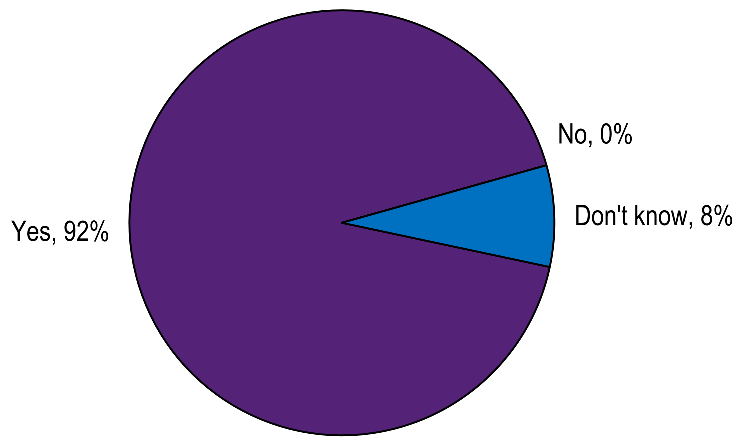
AWARENESS OF SMARTMETER INSTALLATIONS

Reported awareness of SmartMeter installations at commercial locations was very high, with 92% of customers indicating that a SmartMeter was installed at their place of business in the last year.

As far as you know, was the electric meter changed last year and a SmartMeter installed at your place of business?



S5. Recently, Hawaiian Electric has been installing SmartMeters in your area. As far as you know, was the electric meter changed last year and a SmartMeter installed at your place of business? (Base=52)

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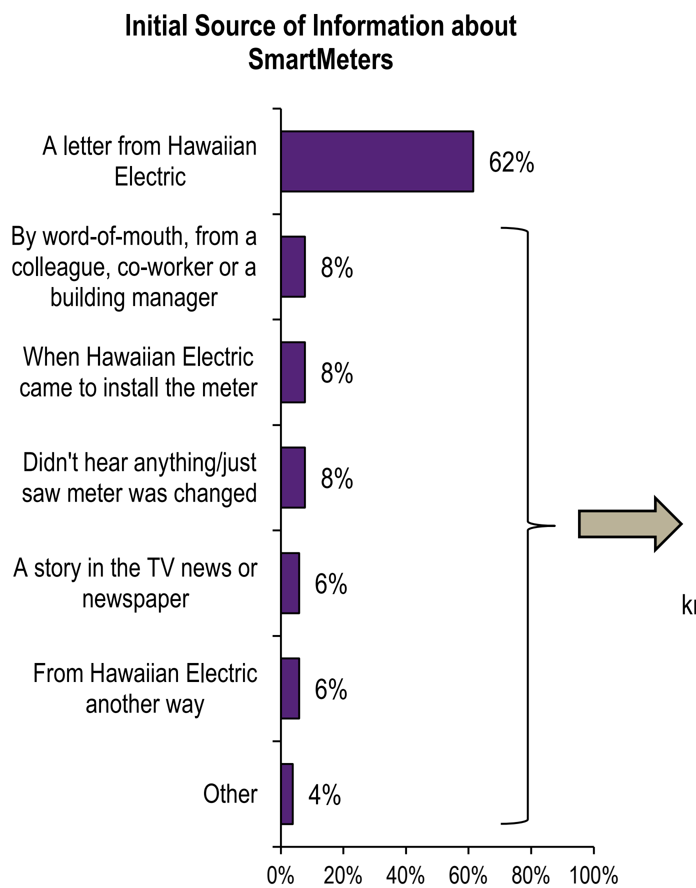
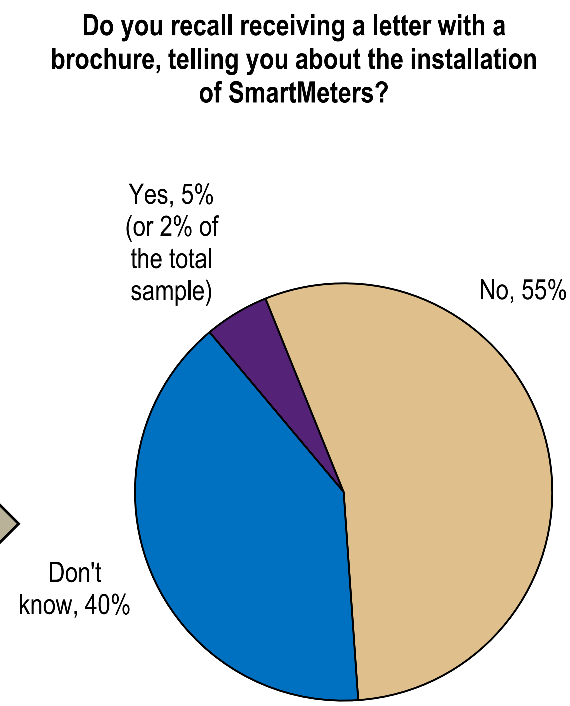
HAWAIIAN ELECTRIC LETTER ABOUT SMARTMETER INSTALLATIONS

The commercial customers surveyed were far more likely to have learned about the SmartMeter installations through an introductory letter from Hawaiian Electric than through any other method. Overall, 64% of the commercial customers surveyed could recall receiving a letter from Hawaiian Electric about the SmartMeter installations (62% unaided and 2% aided).



Q1. Please think back to how you first learned about the installation of SmartMeters in your area? Did you first hear about it through: (Base=52)



Q1a. At some point, do you recall receiving a letter with a brochure, telling you about the installation of SmartMeters in your area? (Base=20)

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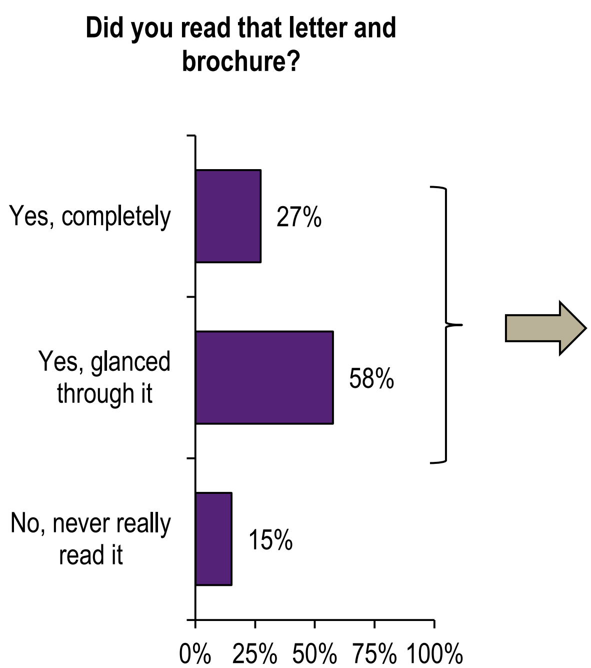
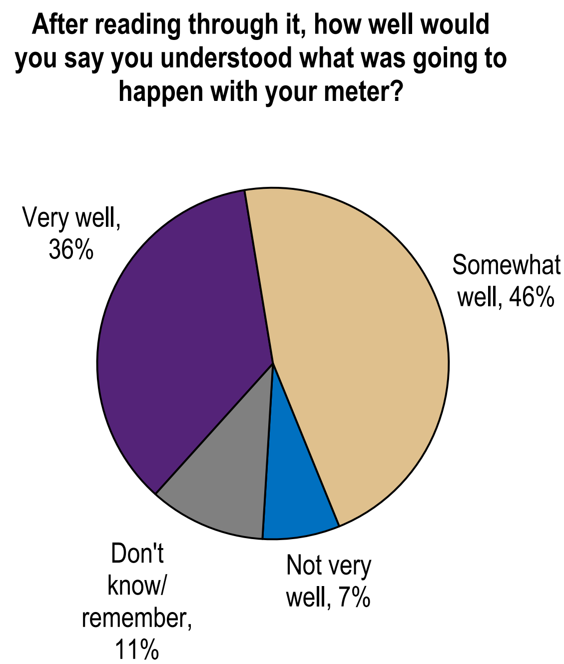
More than four-fifths of the commercial customers who received the introductory letter from Hawaiian Electric read through it completely (27%) or at least glanced through it (58%). After at least glancing through the letter, more than one-third of customers said they understood "very well" what was going to happen with their meter (36%) and nearly one-half said they understood "somewhat well" (46%; note that none of the customers said they "didn't understand it at all").



Q1b. Please think about that letter and brochure that Hawaiian Electric sent. Did you read that letter and brochure? (Base=33)



Q1c. After reading through it, how well would you say you understood what was going to happen with your meter? Would you say you understood: (Base=28)

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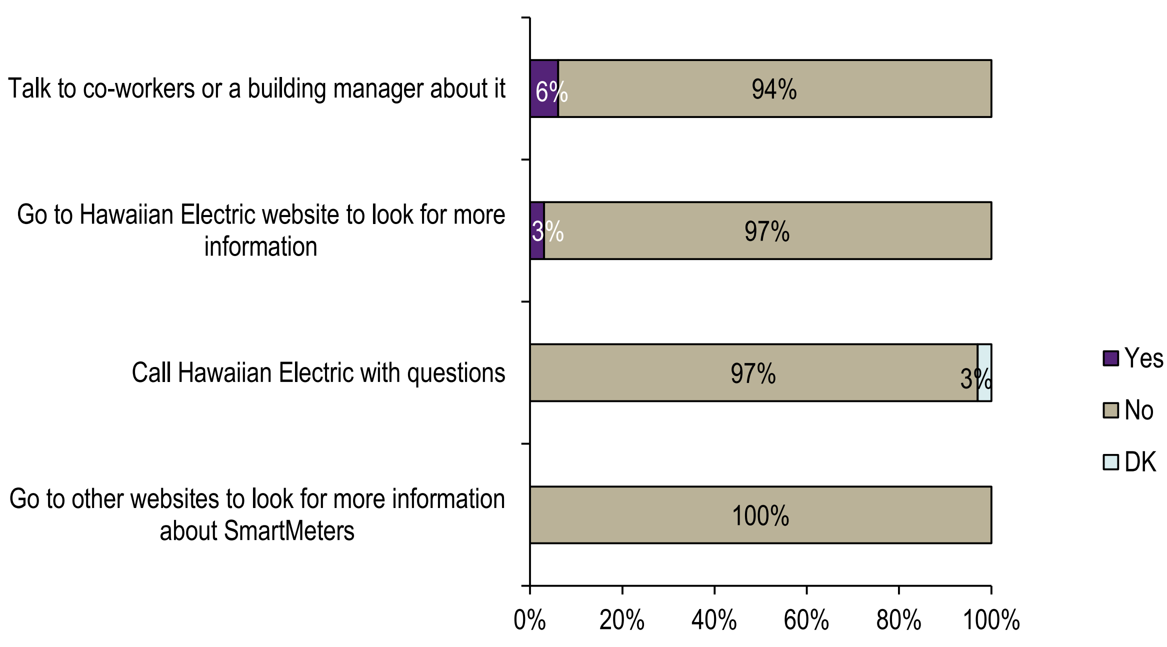
Next, customers were asked if, after receiving the letter, they talked to co-workers or a building manager about it, went to the Hawaiian Electric website to look for more information, called Hawaiian Electric with questions, or went to other websites to look for more information about SmartMeters.

After receiving the introductory letter from Hawaiian Electric, few customers took any action. 6% (or n=2) reportedly talked to co-workers or a building manager about it, while 3% (or n=1) accessed the Hawaiian Electric website for more information. None of the commercial customers reportedly called Hawaiian Electric with questions or accessed other websites to look for more information about SmartMeters.

The customer who accessed the Hawaiian Electric website (n=1) called it "somewhat helpful."

And after receiving that letter, what did you do, if anything? Did you:



Q1d. And after receiving that letter, what did you do, if anything? Did you: (Base=33)

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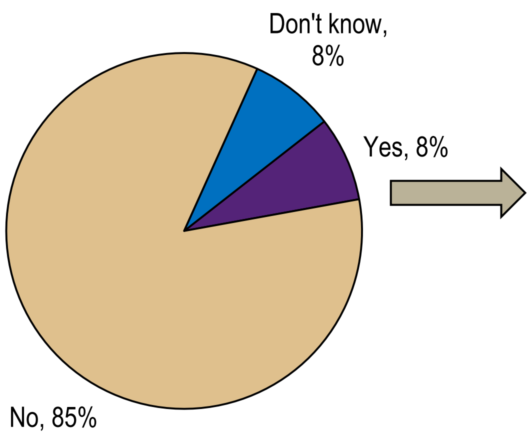
COMMUNITY OPEN HOUSES

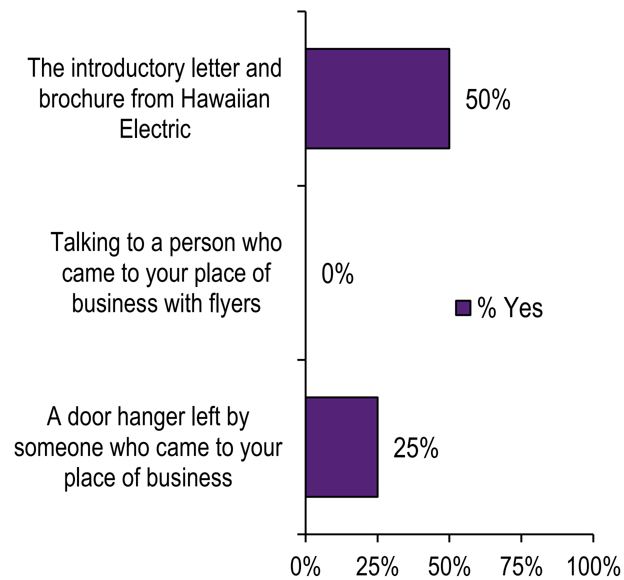
Less than one in ten of commercial customers surveyed could recall an invitation to attend a community open house regarding the installation of the meters, 50% of them through the introductory letter and 25% through the door hanger.

Recall Community Open House Invitation



Q3. Do you recall Hawaiian Electric --- along with its partners Blue Planet Foundation and Hawaii Energy --- inviting you to attend a community open house regarding the installation of the meters? (Base=52)

Do you remember how you learned about the community open house? Was it through:



Q4. Do you remember how you learned about the community open house? Was it through: (Base=4)

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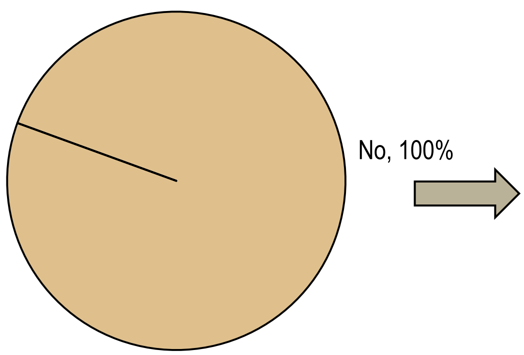
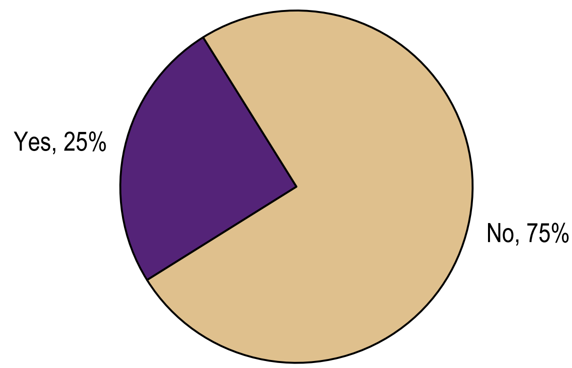
None of the four (4) commercial customers who were aware of the open houses could attend one, although 25% (one person) said they would have attended if they were able.

Did you have an opportunity to attend one of these community open houses?



Had you wanted to attend but were unable?



Q6. Did you have an opportunity to attend one of these community open houses? (Base=4)

Q6a. Had you wanted to attend but were unable? (Base=4)

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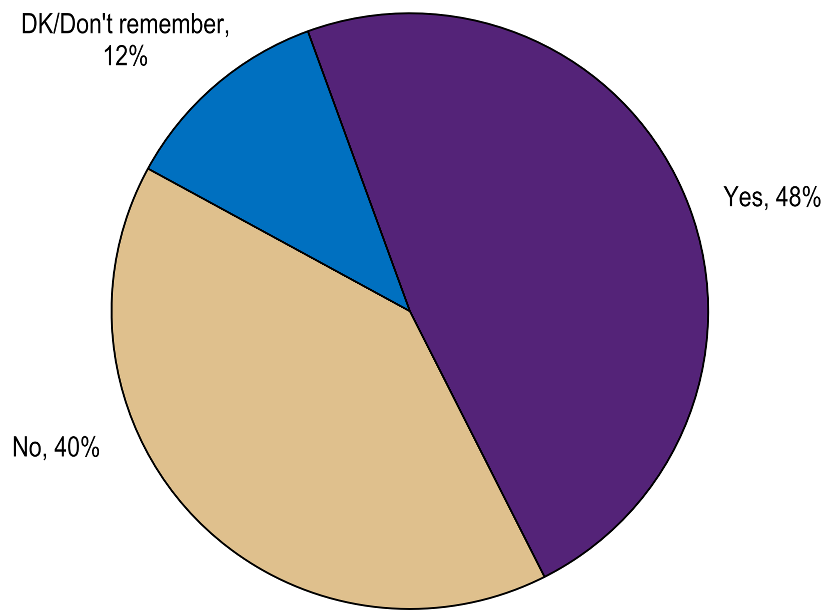
HAWAIIAN ELECTRIC POSTCARD ABOUT THE METER CHANGE

Approximately one-half of the commercial customers surveyed could recall receiving a postcard, telling them that someone would be coming by to change their meter (48%). None of those customers reportedly called Hawaiian Electric to ask for the meter to be installed at another time.

Do you recall your business receiving a postcard?



Q7. Do you recall your business receiving a postcard, telling you that someone would come to change out your meter in the following week or two? (Base=52)

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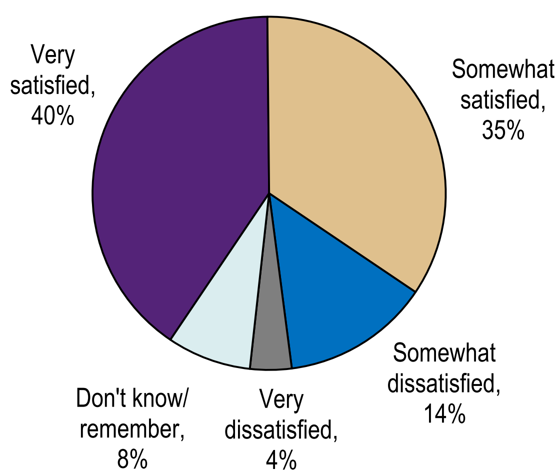
METER CHANGE

Two in five of the commercial customers surveyed reported being "very satisfied" with the advance notice they received regarding the meter change (40%); 35% reported being "somewhat satisfied."

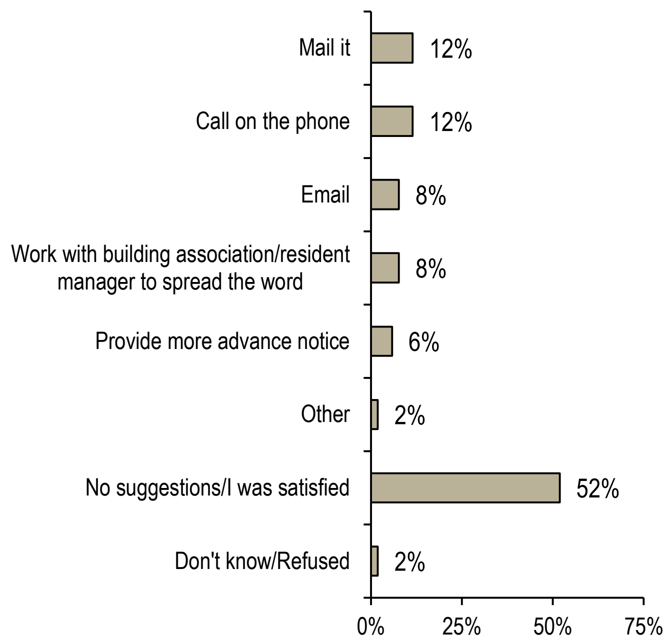
When customers were asked how Hawaiian Electric could improve the notice, one-half indicated that they were satisfied or had no suggestions (52%). Among the suggestions, mailing the notice (12%) and calling it in (12%) topped the list.

How satisfied were you with the advance notice your business received regarding the visit to change out your meter?



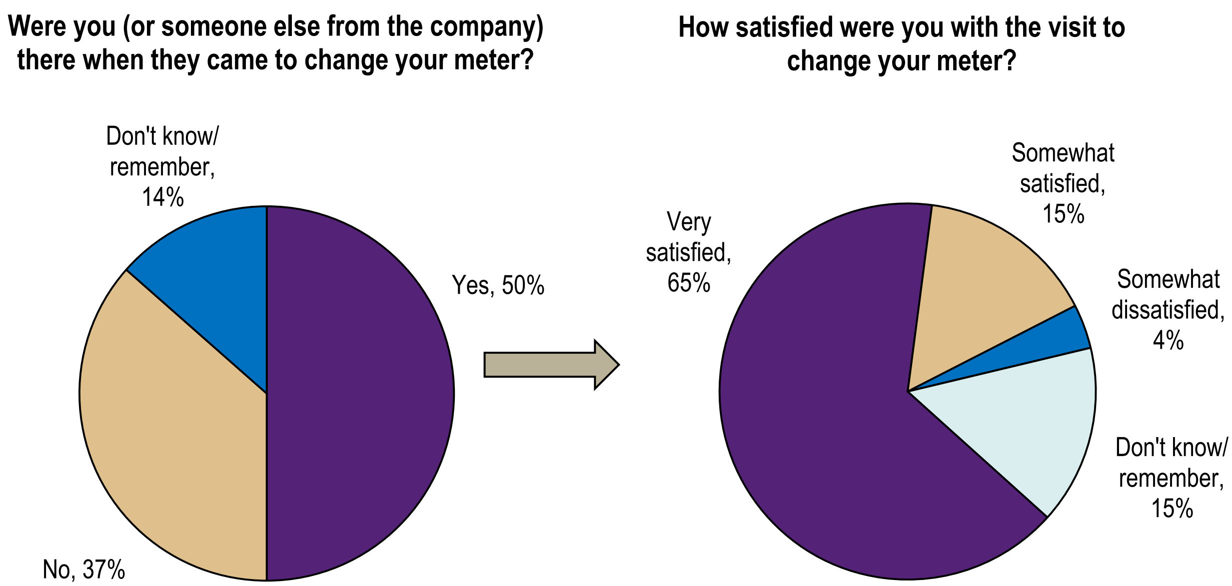
Q9. How satisfied were you with the advance notice your business received regarding the visit to change out your meter? (Base=52)

How could Hawaiian Electric improve the notification to customers regarding the visit to change out the meter? --Top Responses--



Q10. In the future, how could they improve the notification to customers regarding the visit to change out the meter? (Base=52)

One-half of the commercial customers surveyed reportedly were present during the meter change (50%). Two-thirds of those customers said they were "very satisfied" with the visit (65%), with another 15% "somewhat satisfied" (note that none of the customers said they were "very dissatisfied").



Q11. Were you (or someone else from the company) there when they came to change your meter? (Base=52)

Q11a. How satisfied were you with the visit to change your meter? (Base=26)

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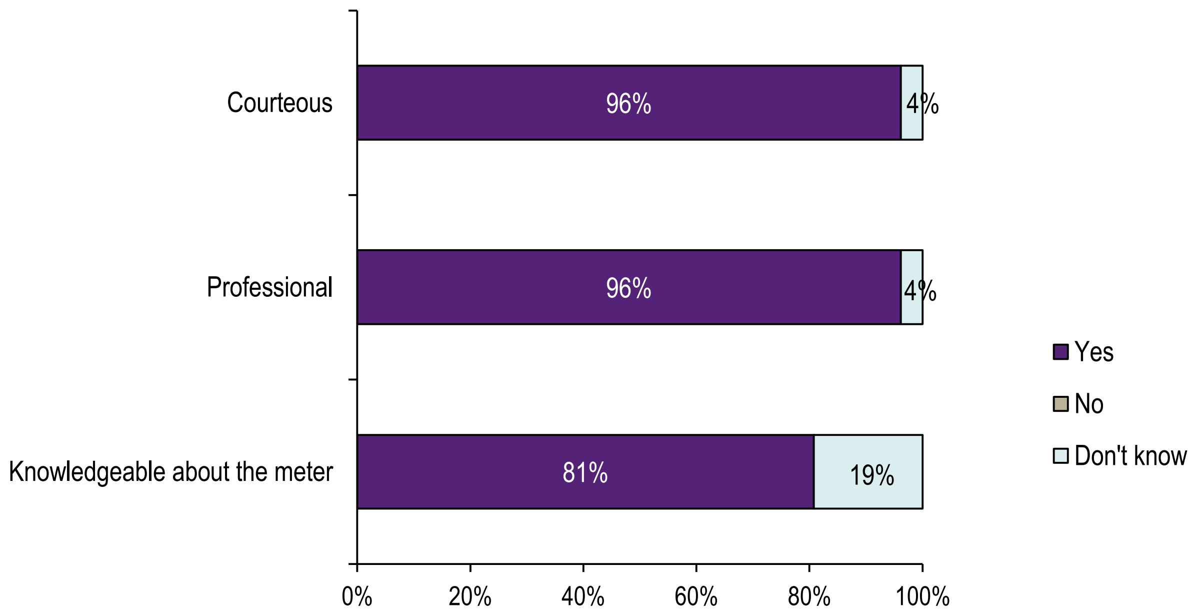
Among the commercial customers who were present, large majorities reported that the person who came to change their meter was courteous (96%) and professional (96%). A large majority of customers also said that the person was knowledgeable about the meter (81%). As shown in the graph below, customers either reported that the person was courteous, professional, or knowledgeable about the meter or that they didn't know; none of responded in the negative.

As far as you can recall, was the person who came to your place of business:



Q12a. As far as you can recall, was the person who came to your place of business: (Base=26)

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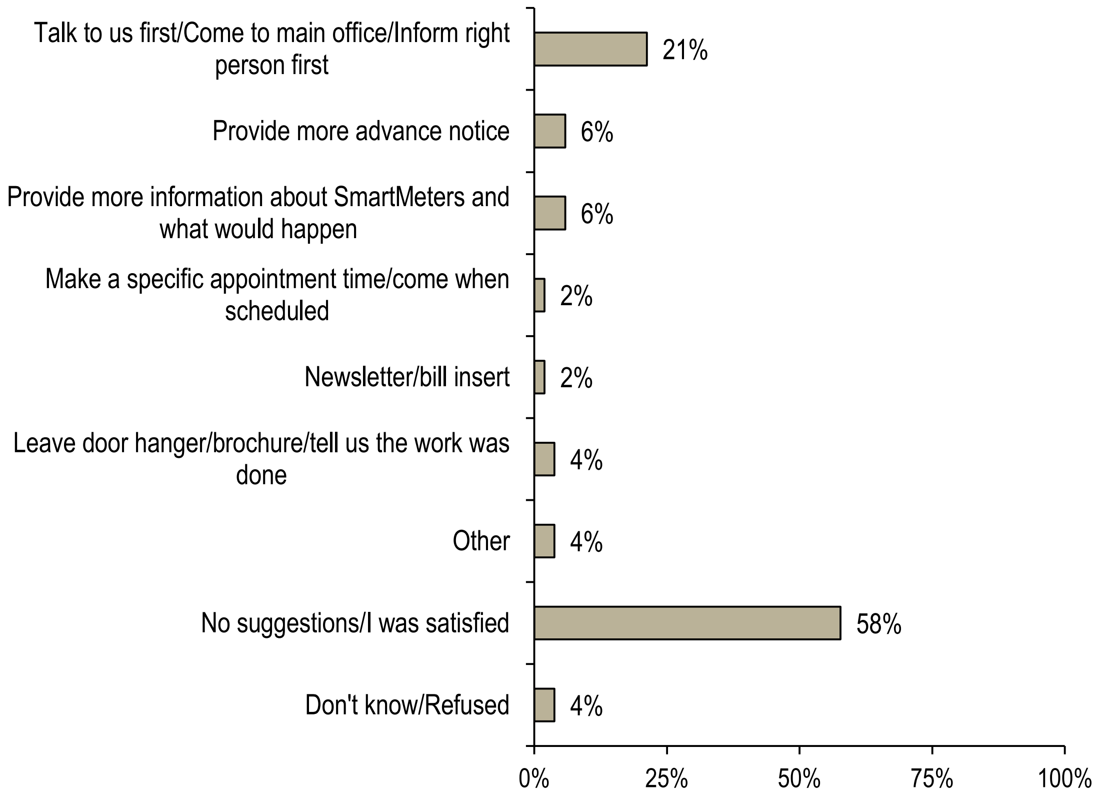
When asked how Hawaiian Electric could improve the visit to business customers to change out the meters, a majority had no suggestions or said they were satisfied with the visit (58%). "Talk to us first" topped the list of suggestions (21%).

Suggestions for Improving the Visit to Business Customers



Q13. In the future, how could they improve the visit to business customers to change out the meters? (Base=52)

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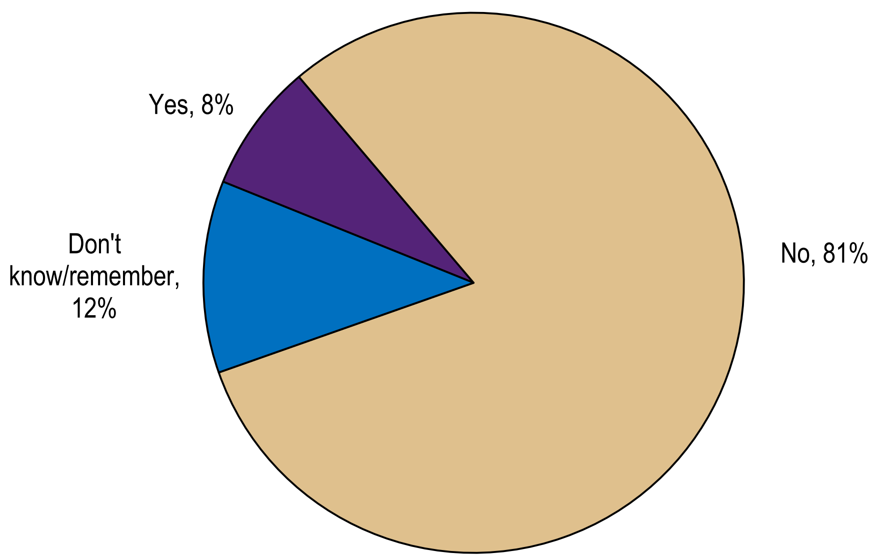
Among the customers who were not present during the meter change, less than one in ten could recall seeing a door hanger or flyer informing them that someone had been there to change their meter (8%). (Note: Reader should be mindful that other employees at the business may have been present.)

Did you or a co-worker ever see a door hanger or flyer saying that someone had been there to change the meter?



Q14. Did you or a co-worker ever see a door hanger or flyer saying that someone had been there to change the meter? (Base=26)

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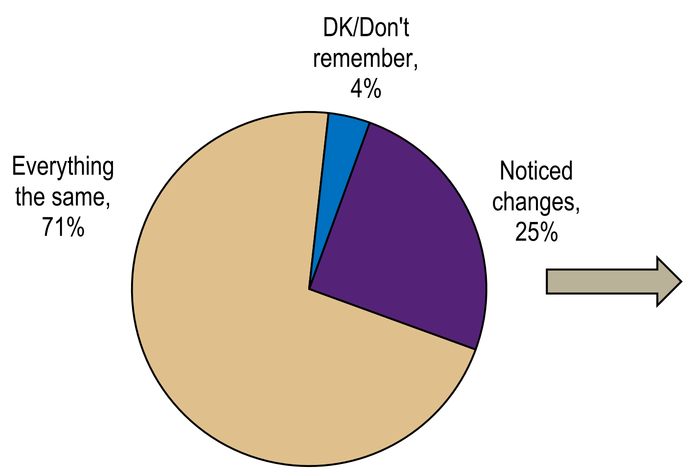
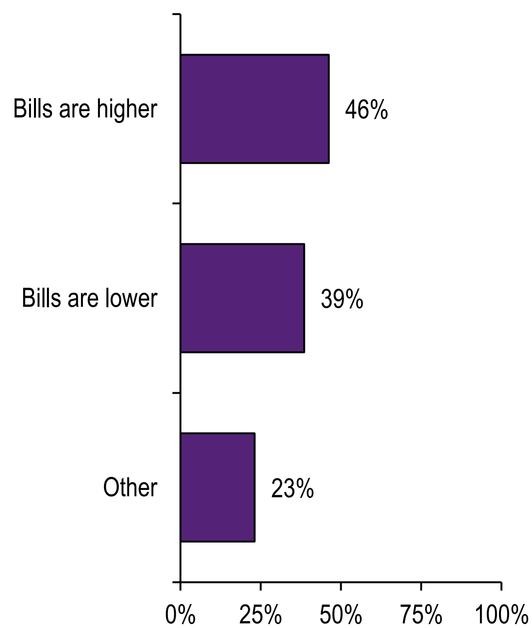
The commercial customers surveyed were also asked if they had noticed any changes since their new meter was installed and 25% said that they had: 46% that their bills are higher and 39% that their bills are lower.

Are there any changes you've noticed?



Q15. Since the new meter was installed, are there any changes you've noticed, or is everything really the same? (Base=52)

What changes have you noticed?



Q15a. What changes have you noticed? (Base=13)

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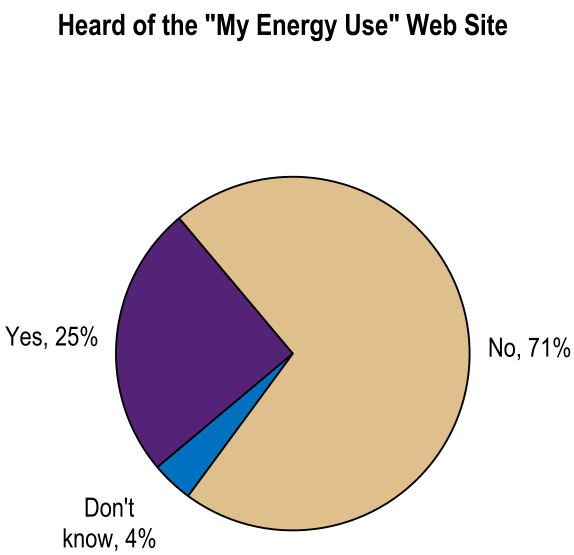
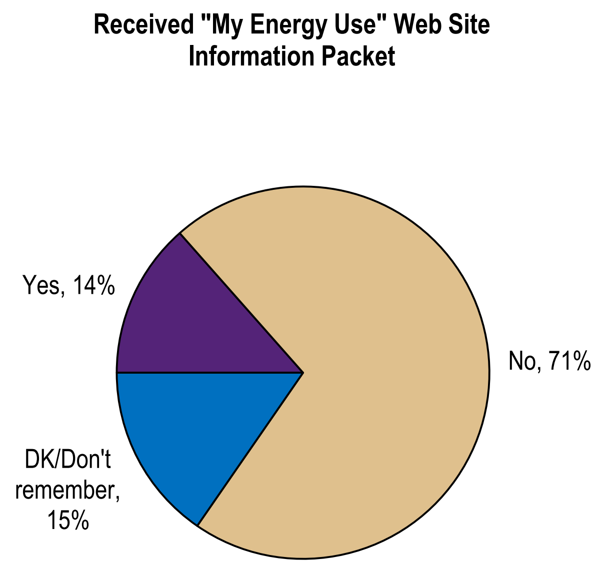
"MY ENERGY USE" WEB PORTAL

One in four of the commercial customers surveyed reportedly had heard of the "My Energy Use" web site (25%), but only 14% said they received a "My Energy Use" information packet.



Q16a. Have you heard of the "My Energy Use" web site? (Base=52)



Q16b. Have you received a packet of information telling you about "My Energy Use," the website that lets you monitor your energy use? (Base=52)

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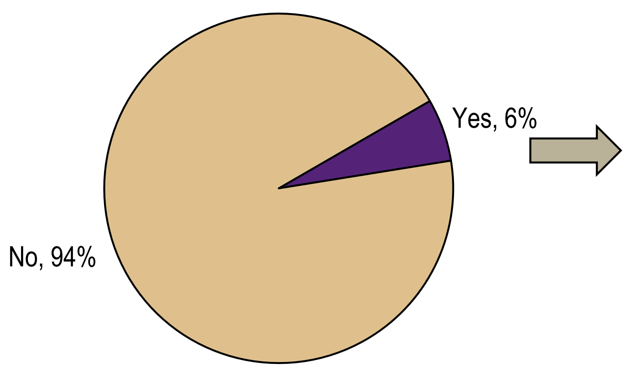
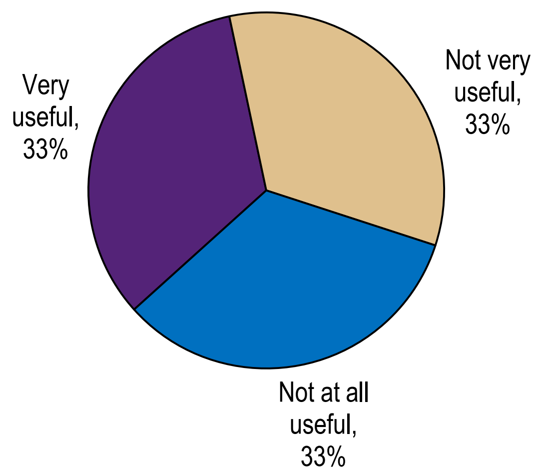
A small proportion of commercial customers said they had logged on to the "My Energy Use" web portal (6%), with 33% of them calling the web portal "very useful" (none of the customers surveyed called it "somewhat useful").

Logged on to the "My Energy Use" Web Portal



Usefulness of "My Energy Use" Web Portal



Q16c. "My Energy Use" is the Web portal on the Hawaiian Electric website that contains real time information about your business' energy use, so you can make decisions about changing behaviors to reduce your usage. Have you logged on to the "My Energy Use" web portal? (Base=52)

Q16d. How useful is the "My Energy Use" web portal? (Base=3)

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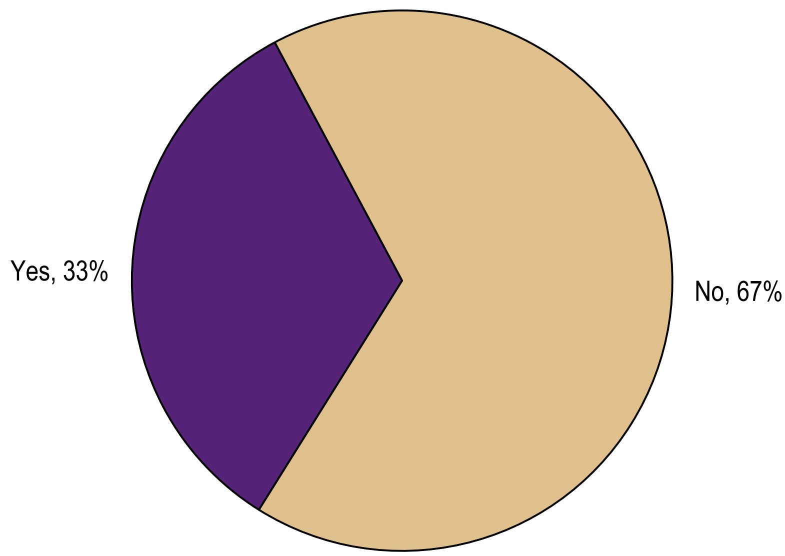
One in three of the commercial customers who had logged on to the "My Energy Use" web portal said they had used the information provided to try to reduce their electricity usage (33%), by unplugging appliances (100%).

Have you used the information provided in the "My Energy Use" web portal to try to reduce your electricity use?



Q16e. Have you used the information provided in the "My Energy Use" web portal to try to reduce your electricity use? (Base=3)

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PART III: ONE-ON-ONE INTERVIEWS WITH INVOLVED EMPLOYEES AND EXTERNAL PARTNERS

SUMMARY OF FINDINGS

Findings from a total of fifteen (15) interviews conducted among persons directly involved in the SmartGrid Initial Phase rollout are presented here. Interviews were conducted among both those involved internally (i.e. twelve [12] Hawaiian Electric employees) and externally (i.e. three [3] people representing organizations involved in contracts or "partnerships" with Hawaiian Electric). The interviews were conducted April 29th to May 7th, 2015 by Rebecca S. Ward, President of Ward Research. The interview length was 30 minutes and interviews were conducted both via telephone and in-person.

OVERALL OPINION

One of the first questions asked of participants was whether or not they viewed the overall rollout to be a success, or did it somehow fall short. Almost all of those interviewed deemed the project a success, citing the successful installation of SmartMeters and the very low levels of customer pushback. Just a few indicated that, while agreeing that the project overall was successful, rolling out the customer-facing technology features of the meters fell short. These individuals cited delays with the web portal and low levels of customer response to the Prepay program as examples of this. All of these will be discussed in greater detail in the sections to follow.

Ultimately, the company successfully changed out residential and commercial customer meters in the Initial Phase circuits, even with delays caused by problems with the meter inventory and quality control processes.

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WHAT WORKED WELL

When participants were asked to identify what, if anything, worked particularly well in the rollout --- either in their respective area of responsibility or in the company's overall execution --- again, the participants pointed to the Customer Engagement process and the actual meter changeouts.

Many of the participants detailed the Customer Engagement process --- including the introductory letter, the open houses, the volunteer canvassing, the postcard alert one week ahead, and the door hanger/"leave behinds" --- and believed that this multi-pronged process resulted in the low deferral rate, lack of public controversy, and generally positive (and limited) media coverage. Some cited the best practices learned from in-person visits to Mainland utilities that had implemented SmartMeter programs and said that the company wisely benefited from their lessons learned.

The partnership with community organizations who are also interested in the SmartGrid project --- Blue Planet Foundation, Hawaii Energy, and KANU Hawaii --- was felt to benefit the project, through implied third party endorsement. Levels of employee volunteerism at Hawaiian Electric, too, were seen (internally) as indicators of their interest in seeing a successful changeout. The volunteer canvassing was felt to facilitate the success of the meter changeout, with canvassers often returning to homes where they had been previously unable to reach someone. Volunteers applauded the use of the app that allowed the real-time display and capture of maps, customer information, and the outcome of each visit. While some of those involved internally and externally were disappointed that more customers did not turn out for the open houses, they understood time demands on customers and the priorities of family needs on weeknights.

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Many, too, cited the project's priority in getting a tremendous amount of work done in a short period of time. They said that top management commitment to the project smoothed the way for a successful Initial Phase.

WHAT DIDN'T GO SO WELL/NEEDS TO BE IMPROVED

Even though describing Initial Phase as a success, many said that more planning time would allow for more clarity around several key issues. These issues are: a) meter specifications and inventory, b) customer-facing technology, and c) additional clarity about roles at Hawaiian Electric.

All of those involved in the implementation of the meter changeout agreed that meter inventory problems caused considerable delays. Additionally, the quality control problems created the need for 100% testing of all of the meters, adding to the time crunch.

Issues related to the rollout of the web portal and the Prepay program, however, are believed to relate to a lack of clarity in the agreement with Silver Springs Network (SSN). The expectations of SSN that Hawaiian Electric would use their "off the shelf" solution collided with the company's desire to customize the product for application on Oahu. Some employees believe greater customer input should have been collected --- and heeded --- prior to issuing the RFP. These employees believe that the company has learned greatly from this experience and would better plan in future SmartMeter rollouts.

OTHER OBSERVATIONS

Interviewed participants were asked to offer any observations they had about three specific areas: initial planning and preparation for the changeout, customer communication and preparations, and post rollout customer communications. Any additional comments in these areas, that are not already discussed, are shown below.

Initial Planning and Preparation for the Changeout

Those with a view into company planning and preparations felt the team did an extraordinary job, given a relatively short horizon for the project. A few felt that, perhaps, greater clarity around the roles and responsibilities in the company would have been helpful. And, as noted above, greater clarity around responsibilities of the customer interface vendor would avoid struggles in contracting and the resulting delays in the web rollout.

Customer Communication and Preparation

As noted earlier in this report, the Customer Engagement process was applauded by all involved, citing the repeated customer touches and resulting in a very low deferral rate. Some also acknowledged, however, that any full implementation of SmartMeters would render impossible the 100% canvassing of neighborhoods, requiring a prioritization of communities.

Post-Rollout Customer Communications

This is an area where some employees and external partners believe the company may have missed an opportunity. These individuals saw an opportunity for the company to build a relationship with the Initial Phase customers, especially along the lines of encouraging web portal usage, modifying their behaviors, and, potentially, reducing their bills. Some thought the company was so happy to have successfully rolled out the meters that this latter portion of the program was “back burnered”.

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CONCLUSIONS

Overall, the twelve (12) employees and three (3) representatives of external partners felt that SmartGrid Initial Phase was a success. They pointed to the successful changeout of the meters and a very low deferral rate as evidence of that success. The Customer Engagement process was cited by all as comprehensive, well designed, and key to the low deferral rate and lack of public controversy.

At the same time, most acknowledged that the rollout of the web portal and Prepay program did not enjoy the same success, as components of the overall rollout.

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APPENDICES

APPENDIX A

WARD RESEARCH, INC.

Smart Grid Survey
WR6486

Last modified March 25, 2015

Sample Elements

[1] ORIGINAL_TELEPHONE
[2] SAMPLE_ID
[3] WARDID
[4] fldCircuit
[5] SAMPLE_ISLAND
[6] Segment
1> Diamond Head
2> Hila 2
3> Luawai
4> Pearl City 1
5> Pearl City 2
6> Kahala
7> Random - Oahu
8> Random - Maui
9> Random - Big Island

[7]ISLAND
1> Oahu
2> Maui
3> Hawaii Island

[8] UTILITY_SHORT
1> HECO
2> MECO
3> HELCO

[9] UTILITY_LONG
1> Hawaiian Electric
2> Maui Electric
3> Hawaii Electric Light Company

[10] SVC_STREET
[11] SVC_SUPPLEMENT
[12] SVC_CITY
[13] SVC_ZIP
[14] Phone1
[15] Phone2
[16] Rate_Category
[17] CARE_OF
[18] BUS_PART
[19] SAMPLE_NAME
[20] MAIL_ADD1
[21] MAIL_ADD2
[22] sessions
[23] average_session_length
[24] first_login
[25] last_login
[26] TOP400NAME
[27] KAM_NAME
[28] KAM_list
[29] Random

****

[40] Hello, I'm _____ with Ward Research, a professional market research firm in Honolulu. We're conducting a brief survey for Hawaiian Electric among their customers on Oahu. This will take about 10 minutes.

[**41**] S1. First of all, is this a landline or a cell phone that we have called?

[IF REFUSED SAY:]
["WE ARE ONLY ASKING BECAUSE WE ARE TRYING TO ACCOUNT FOR HOUSEHOLDS THAT MAY ONLY USE CELL PHONES. ONCE AGAIN, ALL OF YOUR RESPONSES ARE CONFIDENTIAL AND THIS IS FOR RESEARCH ONLY AND IS NOT SALES-RELATED"]

Landline 1
Cell phone.. 2
Refused **(DO NOT READ)** 9

[**IF S1==CELLPHONE THEN ASK**]
[**43**] S2. Are you in a situation where it is safe to complete this survey, and where there will be little to no interruptions?

yes 1
no .... 2 **(MAKE CALL BACK)**

[**44**] S3. Recently. Hawaiian Electric has been installing smart meters in your neighborhood. As far as you know, was your electric meter changed last year and a SmartMeter installed at your home or building?

yes .... 1 [**GO TO S3a**]
no .... 2 [**GO TO S3b**]
don't know **(DO NOT READ)** .... 9 [**GO TO S3a**]

[**45**] S3a. **(IF S3=1)** And are you the person in the household most familiar with this change, or should I speak with someone else?
[**IF NO ASK FOR SOMEONE MOST FAMILIAR WITH METER CHANGE**]
Is there someone else in your household who might be more familiar with this? **IF YES:** May I speak with that person?
[**CONTINUE WITH HOUSEHOLD MEMBER MOST FAMILIAR WITH METER CHANGE**]
1> Yes - PERSON IN HOUSEHOLD MOST FAMILIAR [**GO TO Q1**]
2> No - ASK FOR PERSON MOST FAMILIAR OR MAKE A CALLBACK

[**46**] S3b. **(IF S3=2)** You may have seen a door hanger or a flyer several months ago, saying that Hawaiian Electric had come by and changed your meter to a Smart Meter. Do you remember seeing that door hanger?

yes .... 1 **(GO TO Q1)**
no .... 2 **(GO TO S4)**
don't know **(DO NOT READ)** .... 9 **(GO TO S4)**

[**47**] S4. **(IF S3b=2, 9)** Is there someone else in your household who might be more familiar with this? **(IF YES)** May I speak with that person?

1 > Yes [**GO BACK AND REINTRODUCE TO PERSON MORE FAMILIAR**]
[**GO TO S3**]
2 > No [**TERMINATE**]

[**49**] Q1. Please think back to how you first learned about the installation of SmartMeters in your neighborhood. Did you first hear about it through: **(READ LIST)**

A letter from Hawaiian Electric 1
A story in the tv news or newspaper 2
By word-of-mouth, from a friend or neighbor 3
[**50**] Or through some other means? **(SPECIFY)** ___ 8
Don't know/remember 9

[**51**] Q1a. **(IF Q1<>1)** At some point, do you recall receiving a letter with a brochure, telling you about the installation of SmartMeters in your neighborhood?

yes 1
no .... 2 **(GO TO ~~Q2~~ Q3)**
don't know **(DO NOT READ)** .... 9 **(GO TO ~~Q2~~ Q3)**

[**52**] Q1b. **(IF Q1=1 OR Q1a=1, ASK)** Please think about that letter and brochure that Hawaiian Electric sent. Did you read that letter and brochure?

Yes, completely... 1
Yes, glanced through it 2
No, never really read it .... 3 [**GO TO Q1d**]
DK/don't remember .... 9 [**GO TO Q1d**]

[**53**] Q1c. After reading through it, how well would you say you understood what was going to happen with your meter? Would you say you understood: **(READ LIST)**

Very well 4
Somewhat well 3
Not very well.. 2
Or you didn't understand at all? 1
DK/don't remember 9

[54] Q1d. And after receiving that letter, what did you do, if anything? Did you:

	yes	no	don't know/remember
[**55**] 1e. Call Hawaiian Electric with questions?	1	2	9
[**56**] 1f. Go to the Hawaiian Electric website to look for more information?	1	2	9
[**57**] 1g. Go to other websites to look for more information about SmartMeters?	1	2	9
[**58**] 1h. Talk to friends and neighbors about it?	1	2	9

[**59**] Q2. **(IF Q1e=1)** How helpful was Hawaiian Electric when you called them with questions? (READ LIST)

Very helpful 4
Somewhat helpful.. 3
Not very helpful 2
~~Or~~ not helpful at all 1
Don't know/remember 9

[**60**] Q2b1. **(IF Q2=1 or 2)** Why do you say they were **(NOT VERY/NOT AT ALL)** helpful? **(IF THEY DIDN'T GET SATISFACTORY ANSWER TO THEIR QUESTION, ASK** "And what question(s) did you have that they couldn't help you with?") (PROBE)

[**61**] Q2a. **(IF Q1f=1)** How helpful was the Hawaiian Electric website in providing you more information about the meter change? (READ LIST)

Very helpful	4
Somewhat helpful	3
Not very helpful	2
~~Or~~ not helpful at all	1
Don't know/remember	9

[**62A**] Q2b2. **(IF Q2a=1 or 2)** Why do you say they were **(NOT VERY/NOT AT ALL)** helpful? **(IF THEY DIDN'T GET SATISFACTORY ANSWER TO THEIR QUESTION, ASK** "And what question(s) did you have that ~~they~~ the website couldn't help you with?") (PROBE)

[**63**] Q3. Do you recall Hawaiian Electric --- along with its partners Blue Planet Foundation and Hawaii Energy --- inviting you to attend a community open house regarding the installation of the meters?

yes .... 1 **(CONTINUE TO Q4)**
no .... 2 **(GO TO Q7 INTRO)**
don't know **(DO NOT READ)** .... 9 **(GO TO Q7 INTRO)**

[64] Q4. Do you remember how you learned about the community open house? Was it through:

	yes	no	don't know
[**65**] a. The introductory letter and brochure from Hawaiian Electric?	1	2	9
[**66**] b. Talking to a person going door-to-door with flyers?	1	2	9
[**67**] c. A door hanger left by someone going door-to-door?	1	2	9

[**68**] Q5. **(IF Q4b=1)** And how helpful did you find the in-person visit? (READ LIST)

Very helpful 4
Somewhat helpful 3
Not very helpful 2
Or not helpful at all 1
Don't know/remember 9

[**69**] Q6.Did you have an opportunity to attend one of these community open houses?

yes .... 1 **(CONTINUE TO Q6b.)**
no .... 2 **(CONTINUE TO Q6a.)**
don't know/remember **(DO NOT READ)** .... 9 **(GO TO Q7 INTRO)**

[**70**] Q6a. **(Q6=2)** Had you wanted to attend but were unable?

yes .... 1 **(GO TO Q7 INTRO)**
no .... 2 **(GO TO Q7 INTRO)**
don't know/remember **(DO NOT READ)** .... 9 **(GO TO Q7 INTRO)**

[**71**] Q6b. **(Q6=1)** How helpful did you find the information shared at this open house? (READ LIST)

Very helpful 4
Somewhat helpful 3
Not very helpful 2
Or not helpful at all 1
don't know/remember **(DO NOT READ)** 9

[**72A**] Q6c. What was helpful, and what if anything, would have made the information more helpful? **(PROBE THOROUGHLY)**

____

____

____

Now, regarding the visit to your home to change the meter…….

[**73**] Q7.Do you recall your household receiving a postcard, telling you that someone would come to change out your meter in the following week or two?

yes .... 1 **(GO TO Q8)**
no .... 2 **(GO TO Q9)**
don't know/remember **(DO NOT READ)** .... 9 **(GO TO Q9)**

(IF Q7=1)
[**74**] Q8.At that point, did you call Hawaiian Electric to ask for the meter to be installed at another time?

yes .... 1 **(GO TO Q8a.)**
no .... 2 **(GO TO Q9)**
don't know/remember **(DO NOT READ)** .... 9 **(GO TO Q9)**

(IF YES, Q8=1)
[**75**] Q8a. And were they able to accommodate your request?

yes 1
no 2
don't know/remember **(DO NOT READ)** 9

[**76**] Q9.How satisfied were you with the advance notice your household received regarding the visit to change out your meter? (READ LIST)

Very satisfied... 4
Somewhat satisfied 3
Somewhat dissatisfied 2
Very dissatisfied 1
don't know/remember **(DO NOT READ)** 9

[**77A-G**] Q10. In the future, how could they improve the notification to customers regarding the visit to change out the meter? (PROBE)

____

____

____

____

[**78**] Q11.Were you (or someone else in your household) home when they came to change your meter?

yes .... 1 **(GO TO Q11a.)**
no .... 2 **(GO TO Q13)**
don't know/remember **(DO NOT READ)** .... 9 **(GO TO Q13)**

(IF YES, Q11=1)
[**79**] Q11a.How satisfied were you with the visit to change your meter? (READ LIST)

Very satisfied.. 4
Somewhat satisfied 3
Somewhat dissatisfied 2
Very dissatisfied 1
don't know/remember **(DO NOT READ)** 9

[80] Q12. As far as you can recall, was the person who came to your house:

	Yes	No	DK
a. [**81**] Courteous?	1	2	9
b. [**82**] Professional?	1	2	9
c. [**83**] Knowledgeable about the meter?	1	2	9

[**BASE ALL**]
[**84A-C**] Q13. In the future, how could they improve the visit to customers' homes to change out the meters? (PROBE)

____

____

____

____

(IF NO, WEREN'T HOME, Q11=2, 9 AND QS3b NOT ASKED)
[**85**] Q14. Did you or another household member ever see a door hanger or flyer saying that someone had been there to change your meter?

yes 1
no 2
don't know/remember **(DO NOT READ)** 9

[**86**] Q15. Since the new meter was installed at your home, are there any changes you've noticed, or is everything really the same?

Noticed changes .... 1 **(GO TO Q15a.)**
Everything the same .... 2 **(GO TO Q16)**
don't know/remember **(DO NOT READ)** .... 9 **(GO TO Q16)**

(IF Q15=1)
[**87A-C**] Q15a. What changes have you noticed? **(DO NOT READ)**

Bills are higher 1
Bills are lower... 2
Meter making noises 3
[**88A**] Other ______________________________ 8

[**89**] Q16. Have you heard of the "My Energy Use" Web site?

yes 1
no 2
don't know **(DO NOT READ)** 9

[**90**] Q16a. Have you received a packet of information telling you about MyEnergyUse, the website that lets you monitor your energy use?

yes 1
no 2
don't know/remember **(DO NOT READ)** 9

[**91**] Q16b."My Energy Use" is the Web portal on the Hawaiian Electric website that contains real time information about your household energy use, so you can make decisions about changing behaviors to reduce your usage. Have you logged on to the "My Energy Use" Web portal?

yes .... 1 **(GO TO Q16c.)**
no .... 2 **(GO TO Q DEMOS)**
don't know **(DO NOT READ)** .... 9 **(GO TO Q DEMOS)**

[**92**] Q16c. How useful is the My Energy Use web portal? (READ LIST)

Very useful.. 4
Somewhat useful... 3
Not very useful 2
Not at all useful 1
don't know **(DO NOT READ)** 9

[**93**] Q16d.Have you used the information provided in the "My Energy Use" Web portal to try to reduce your electricity use?

yes 1
no .... 2 **(SKIP TO Q16f)**
don't know **(DO NOT READ)** .... 9 **(SKIP TO Q16f)**

[**94A-C**] Q16e.What steps did you take to reduce your electricity use? **(DO NOT READ LIST)**

Unplugged appliances...................................... 1
Adjusted time on water heaters or used less electricity during peak times......................... 2
Reviewed and became aware of usage 3
[**95A**] other 8
don't know **(DO NOT READ)** 9

[**96A-B**] Q16f. What, if anything, could improve the usefulness of the My Energy Use web portal? (PROBE)

____

____

____

And now we have just a few questions so that we can describe the sample of people that we talked to……

[**97**] Q17. Do you own or rent your home?

own 1
rent.. 2
occupy without payment.................................. 3
don't know/refused 9

[**98**] Q18. Is that a house, apartment, condominium, or a townhouse?

house 1
apartment 2
condominium 3
townhouse 4
[**99**] other 8
don't know/refused 9

[**100**] Q19. Including yourself, how many people live in your household?
REF=99 (DO NOT READ)

[**101**] Q20. What is your zip code?
DK/REF=96866 (DO NOT READ)

[**102**] Q21. What is your ethnic background?

Caucasian 1
Chinese 2
Filipino 3
Hawaiian/part-Hawaiian 4
Japanese 5
mixed, not Hawaiian 6
Black or African-American 7
[**103**] other (SPECIFY) 8
don't know/refused 9

[**104**] Q22. How many years have you lived in Hawaii?

less than 1 year 1
1 to 5 years 2
6 to 10 years 3
11 to 20 years 4
over 20, not lifetime 5
lifetime 6
don't know/refused 9

[**105**] Q23. How many years have you lived at your current address?

less than 1 year	1
1 to 5 years	2
6 to 10 years	3
11 to 20 years	4
over 20, not lifetime	5
lifetime	6
don't know/refused	9

[**106**] Q24. What is your age? **(READ LIST)**

18 to 24	1
25 to 34	2
35 to 44	3
45 to 54	4
55 to 64	5
65 or older	6
don't know/refused	9

[**107**] Q25. What was the total 2014 income before taxes, for all members of your household? Was it **(READ LIST)**

less than $25,000	1
$25,000 to less than $50,000	2
$50,000 to less than $75,000	3
$75,000 to less than $100,000	4
$100,000 to less than $150,000	5
$150,000 and over	6
don't know/refused	9

[**108**] Q26. Gender **(DO NOT ASK)**

Male	1
Female	2

[**109**] In case my supervisor wants to verify that I completed this survey with you may I have just your first name, please?

[110] That's all the questions. Thank you for taking the time to do the survey.

WARD RESEARCH, INC.

APPENDIX B

Smart Grid Survey: Commercial
WR6764

Last modified April 28, 2015

Sample Elements

[**1**] ORIGINAL_TELEPHONE
[**2**] SAMPLE_ID
[**3**] WARDID
[**4**] fldCircuit
[**5**] SAMPLE_ISLAND
[**6**] Segment
 1> Diamond Head
 2> Hila 2
 3> Luawai
 4> Pearl City 1
 5> Pearl City 2
 6> Kahala
 7> Random - Oahu
 8> Random - Maui
 9> Random - Big Island

[**7**]ISLAND
 1> Oahu
 2> Maui
 3> Hawaii Island

[**8**] UTILITY_SHORT
 1> HECO
 2> MECO
 3> HELCO

[**9**] UTILITY_LONG
 1> Hawaiian Electric
 2> Maui Electric
 3> Hawaii Electric Light Company

[**10**] SVC_STREET
[**11**] SVC_SUPPLEMENT
[**12**] SVC_CITY
[**13**] SVC_ZIP
[**14**] Phone1
[**15**] Phone2
[**16**] Rate_Category
[**17**] CARE_OF
[**18**] BUS_PART
[**19**] SAMPLE_NAME
[**20**] MAIL_ADD1
[**21**] MAIL_ADD2
[**22**] sessions
[**23**] average_session_length
[**24**] first_login
[**25**] last_login
[**26**] TOP400NAME
[**27**] KAM_NAME
[**28**] KAM_list
[**29**] Random
[**30**] Duplicate codes
[**31**] Comments

****

[**40**] Hello, I'm ______ with Ward Research, a professional market research firm in Honolulu. We're conducting a brief survey for Hawaiian Electric among their business customers. This will take about 10 minutes.

S1. Just to verify, have I reached (COMPANY)?

Yes.. 1
No .... 2 (TERMINATE)
Refused.. 9 (TERMINATE)

[IF NO ASK THEN TERMINATE]

[**38**] S2. What is the name of the business I have reached?

____

[**41**] S1. First of all, is this a landline or a cell phone that we have called?

[IF REFUSED SAY:]
["WE ARE ONLY ASKING BECAUSE WE ARE TRYING TO ACCOUNT FOR RESPONDENTS THAT MAY ONLY USE CELL PHONES. ONCE AGAIN, ALL OF YOUR RESPONSES ARE CONFIDENTIAL AND THIS IS FOR RESEARCH ONLY AND IS NOT SALES-RELATED"]

Landline 1
Cell phone 2
Refused **(DO NOT READ)** 9

[**IF S1==CELLPHONE THEN ASK**]

[**43**] S2. Are you in a situation where it is safe to complete this survey, and where there will be little to no interruptions?

yes 1
no .... 2 **(MAKE CALL BACK)**

[**44**] S3. Recently. Hawaiian Electric has been installing smart meters in your area. As far as you know, was the electric meter changed last year and a SmartMeter installed at your place of business?

yes .... 1 [**GO TO S3a**]
no .... 2 [**GO TO S3b**]
don't know **(DO NOT READ)** .... 9 [**GO TO S3a**]

[**45**] S3a. **(IF S3=1)** And are you the person in the company most familiar with this change, or should I speak with someone else?
[**IF NO ASK FOR SOMEONE MOST FAMILIAR WITH METER CHANGE**]
Is there someone else in the company who might be more familiar with this? **IF YES:** May I speak with that person?
[**CONTINUE WITH PERSON MOST FAMILIAR WITH METER CHANGE**]
1> Yes - PERSON IN COMPANY MOST FAMILIAR [**GO TO Q1**]
2> No - ASK FOR PERSON MOST FAMILIAR OR MAKE A CALLBACK

[**46**] S3b. **(IF S3=2~~, 9~~)** You may have seen a door hanger or a flyer several months ago, saying that Hawaiian Electric had come by and changed the meter to a Smart Meter. Do you remember seeing that door hanger?

yes .... 1 **(GO TO Q1)**
no .... 2 **(GO TO S4)**
don't know **(DO NOT READ)** .... 9 **(GO TO S4)**

[**47**] S4. **(IF S3b=2, 9)** Is there someone else in the company who might be more familiar with this? **(IF YES)** May I speak with that person?
1 > Yes [**GO BACK AND REINTRODUCE TO PERSON MORE FAMILIAR**] [**GO TO S3**]
2 > No [**TERMINATE**]

[**49**] Q1. Please think back to how you first learned about the installation of SmartMeters in your area. Did you first hear about it through: **(READ LIST)**

A letter from Hawaiian Electric 1
A story in the tv news or newspaper 2
By word-of-mouth, from a colleague,
co-worker or a building manager 3
[**50**] Or through some other means? **(SPECIFY)** ___ 8
Don't know/remember... 9

[**51**] Q1a. **(IF Q1<>1)** At some point, do you recall receiving a letter with a brochure, telling you about the installation of SmartMeters in your area?

yes 1
no .... 2 **(GO TO Q3)**
don't know **(DO NOT READ)** .... 9 **(GO TO Q3)**

[**52**] Q1b. **(IF Q1=1 OR Q1a=1, ASK)** Please think about that letter and brochure that Hawaiian Electric sent. Did you read that letter and brochure?

Yes, completely.. 1
Yes, glanced through it 2
No, never really read it................................... 3 [**GO TO Q1d**]
DK/don't remember .... 9 [**GO TO Q1d**]

[**53**] Q1c. After reading through it, how well would you say you understood what was going to happen with your meter? Would you say you understood: **(READ LIST)**

Very well 4
Somewhat well 3
Not very well.. 2
Or you didn't understand at all? 1
DK/don't remember 9

[54] Q1d. And after receiving that letter, what did you do, if anything? Did you:

	yes	no	don't know/remember
[**55**] 1e. Call Hawaiian Electric with questions?	1	2	9
[**56**] 1f. Go to the Hawaiian Electric website to look for more information?	1	2	9
[**57**] 1g. Go to other websites to look for more information about SmartMeters?	1	2	9
[**58**] 1h. Talk to co-workers or a building manager about it?	1	2	9

[**59**] Q2. **(IF Q1e=1)** How helpful was Hawaiian Electric when you called them with questions? (READ LIST)

Very helpful	4
Somewhat helpful	3
Not very helpful	2
~~Or~~ not helpful at all	1
Don't know/remember	9

[**60**] Q2b1. **(IF Q2=1 or 2)** Why do you say they were **(NOT VERY/NOT AT ALL)** helpful? **(IF THEY DIDN'T GET SATISFACTORY ANSWER TO THEIR QUESTION, ASK** "And what question(s) did you have that they couldn't help you with?") (PROBE)

[**61**] Q2a. **(IF Q1f=1)** How helpful was the Hawaiian Electric website in providing you more information about the meter change? (READ LIST)

Very helpful	4
Somewhat helpful	3
Not very helpful	2
~~Or~~ not helpful at all	1
Don't know/remember	9

[**62A**] Q2b2. **(IF Q2a=1 or 2)** Why do you say they were **(NOT VERY/NOT AT ALL)** helpful? **(IF THEY DIDN'T GET SATISFACTORY ANSWER TO THEIR QUESTION, ASK** "And what question(s) did you have that ~~they~~ the website couldn't help you with?") (PROBE)

[**63**] Q3. Do you recall Hawaiian Electric --- along with its partners Blue Planet Foundation and Hawaii Energy --- inviting you to attend a community open house regarding the installation of the meters?

yes .... 1 **(CONTINUE TO Q4)**
no .... 2 **(GO TO Q7 INTRO)**
don't know **(DO NOT READ)** .... 9 **(GO TO Q7 INTRO)**

[64] Q4. Do you remember how you learned about the community open house? Was it through:

	yes	no	don't know
[**65**] a. The introductory letter and brochure from Hawaiian Electric?	1	2	9
[**66**] b. Talking to a person who came to your place of business with flyers?	1	2	9
[**67**] c. A door hanger left by someone who came to your place of business?	1	2	9

[**68**] Q5. **(IF Q4b=1)** And how helpful did you find the in-person visit? (READ LIST)

Very helpful 4
Somewhat helpful...................................... 3
Not very helpful 2
Or not helpful at all 1
Don't know/remember 9

[**69**] Q6.Did you have an opportunity to attend one of these community open houses?

yes .... 1 **(CONTINUE TO Q6b.)**
no .... 2 **(CONTINUE TO Q6a.)**
don't know/remember **(DO NOT READ)** .... 9 **(GO TO Q7 INTRO)**

[**70**] Q6a. **(Q6=2)** Had you wanted to attend but were unable?

yes .... 1 **(GO TO Q7 INTRO)**
no .... 2 **(GO TO Q7 INTRO)**
don't know/remember **(DO NOT READ)** .... 9 **(GO TO Q7 INTRO)**

[**71**] Q6b. **(Q6=1)** How helpful did you find the information shared at this open house? (READ LIST)

Very helpful 4
Somewhat helpful...................................... 3
Not very helpful 2
Or not helpful at all 1
don't know/remember **(DO NOT READ)** 9

[**72A**] Q6c. What was helpful, and what if anything, would have made the information more helpful? **(PROBE THOROUGHLY)**

____

____

____

Now, regarding the visit to your business to change the meter…….

[**73**] Q7.Do you recall your business receiving a postcard, telling you that someone would come to change out your meter in the following week or two?

yes .... 1 **(GO TO Q8)**
no .... 2 **(GO TO Q9)**
don't know/remember **(DO NOT READ)** .... 9 **(GO TO Q9)**

(IF Q7=1)
[**74**] Q8.At that point, did you call Hawaiian Electric to ask for the meter to be installed at another time?

yes .... 1 **(GO TO Q8a.)**
no .... 2 **(GO TO Q9)**
don't know/remember **(DO NOT READ)** .... 9 **(GO TO Q9)**

(IF YES, Q8=1)
[**75**] Q8a. And were they able to accommodate your request?

yes 1
no 2
don't know/remember **(DO NOT READ)** 9

[**76**] Q9.How satisfied were you with the advance notice your business received regarding the visit to change out your meter? (READ LIST)

Very satisfied... 4
Somewhat satisfied 3
Somewhat dissatisfied 2
Very dissatisfied 1
don't know/remember **(DO NOT READ)** 9

[**77A-G**] Q10. In the future, how could they improve the notification to customers regarding the visit to change out the meter? (PROBE)

____

____

____

____

[**78**] Q11.Were you (or someone else from the company) there when they came to change your meter?

yes .... 1 **(GO TO Q11a.)**
no .... 2 **(GO TO Q13)**
don't know/remember **(DO NOT READ)** .... 9 **(GO TO Q13)**

(IF YES, Q11=1)
[**79**] Q11a.How satisfied were you with the visit to change your meter? (READ LIST)

Very satisfied.. 4
Somewhat satisfied 3
Somewhat dissatisfied 2
Very dissatisfied 1
don't know/remember **(DO NOT READ)** 9

[80] Q12. As far as you can recall, was the person who came to your place of business:

	Yes	No	DK
a. [**81**] Courteous?	1	2	9
b. [**82**] Professional?	1	2	9
c. [**83**] Knowledgeable about the meter?	1	2	9

[**BASE ALL**]
[**84A-D**] Q13. In the future, how could they improve the visit to business customers' to change out the meters? (PROBE)

____

____

____

____

(IF NO, WEREN'T HOME, Q11=2, 9 AND QS3b NOT ASKED)
[**85**] Q14. Did you or a co-worker ever see a door hanger or flyer saying that someone had been there to change the meter?

yes 1
no 2
don't know/remember **(DO NOT READ)** 9

[**86**] Q15. Since the new meter was installed, are there any changes you've noticed, or is everything really the same?

Noticed changes .... 1 **(GO TO Q15a.)**
Everything the same .... 2 **(GO TO Q16)**
don't know/remember **(DO NOT READ)** .... 9 **(GO TO Q16)**

(IF Q15=1)
[**87A-C**] Q15a. What changes have you noticed? **(DO NOT READ)**

Bills are higher 1
Bills are lower.. 2
Meter making noises 3
[**88A-B**] Other___________________________ 8

[**89**] Q16. Have you heard of the "My Energy Use" Web site?

yes 1
no 2
don't know **(DO NOT READ)** 9

[**90**] Q16a. Have you received a packet of information telling you about MyEnergyUse, the website that lets you monitor your energy use?

yes 1
no 2
don't know/remember **(DO NOT READ)** 9

[**91**] Q16b."My Energy Use" is the Web portal on the Hawaiian Electric website that contains real time information about your business energy use, so you can make decisions about changing behaviors to reduce your usage. Have you logged on to the "My Energy Use" Web portal?

yes .... 1 **(GO TO Q16c.)**
no .... 2 **(GO TO Q DEMOS)**
don't know **(DO NOT READ)** .... 9 **(GO TO Q DEMOS)**

[**92**] Q16c. How useful is the My Energy Use web portal? (READ LIST)

Very useful.. 4
Somewhat useful... 3
Not very useful 2
Not at all useful 1
don't know **(DO NOT READ)** 9

[**93**] Q16d.Have you used the information provided in the "My Energy Use" Web portal to try to reduce your electricity use?

yes 1
no .... 2 **(SKIP TO Q16f)**
don't know **(DO NOT READ)** .... 9 **(SKIP TO Q16f)**

[**94A-C**] Q16e.What steps did you take to reduce your electricity use? **(DO NOT READ LIST)**

Unplugged appliances....................................... 1
Adjusted time on water heaters or used less electricity during peak times......................... 2
Reviewed and became aware of usage 3
[**95A**] other 8
don't know **(DO NOT READ)** 9

[**96A-B**] Q16f. What, if anything, could improve the usefulness of the My Energy Use web portal? (PROBE)

____

____

____

And now we have just a few questions so that we can describe the sample of businesses that we talked to……

~~Q17. According to our records, your company is a(n) (RESTORE: BLDGTYPE). Is this correct?~~

~~Yes, correct .... 1~~
~~No, not correct .... 2~~
~~don't know/refused .... 9~~

[NOT IN SAMPLE FILE]

[**97**] Q18. How would you describe your business?

Agricultural Pumping Station 1
Air Transportation Facility 2
Church 3
Cold Storage Facility 4
Communication Utility (e.g., TV station, radio station, cable provider, telephone utility) 5
Construction Manager 6
Education Facility 7
Entertainment Venue (e.g., movie theater, museum, country club, sports arena, concert hall 8
Farm 9
Food Production or Processing Plant 10
Health Facility 11
Hotel 12
Manufacturing Facility 13
Military Base 14
Non-Profit 15
Office Building 16
Other Pumping Station 17
Real estate/Property management 18
Restaurant 19
Retail – Food Store (e.g., supermarket, grocery, mom & pop, 7-11) 20
Retail – Non-Food Store 21
Service Provider (e.g., beauty parlor, photo-copy shop, laundromat) 22
Water Supply or Sewage Facility 23
Wholesaler 24
[**98**] other 25
don't know/refused 26

[**99**] Q19. How many employees work at this location, including full and part-time employees? DK/REF=9999 (DO NOT READ)

[**100**] Q20. Please stop me when I reach the category that includes the total business revenues at your business location in 2014.

under $50,000 1
$50,000 to $100,000 ($99,999) 2
$100,000 to $250,000 ($249,999) 3
$250,000 to $500,000 ($499,999) 4
$500,000 to $1 million ($999,999) 5
$1 million to $5 million ($4,999,999) 6
$5 million to $10 million ($9,999,999) 7
$10 million or more 8
Don’t know/refused 9

[**101**] Q26. Gender **(DO NOT ASK)**

Male 1
Female 2

[**102**] In case my supervisor wants to verify that I completed this survey with you may I have just your first name, please?

[103] That's all the questions. Thank you for taking the time to do the survey.

APPENDIX C

HECO SMARTGRID PROCESS EVALUATIONS
1:1 INTERVIEWS

Introductions, etc.

Q. Would be helpful for me if you could start by helping me understand your role in the SmartGrid Phase 0 project. (IF NOT CLEAR) And, in this capacity, did you have contact with customers in the pilot circuits?

Q. So let's start big picture. Overall, for Hawaiian Electric, how do you feel the rollout went? Would you say it was a success or not?

Q. From your perspective, what went particularly well? (PROBE FULLY)

Q. And what, if anything, did not go quite so well, or what needs to be improved?

Q. Now let's walk through the processes and talk about any observations you have about what went well, and what might need improvement, at each step along the way. The first would be:

a. Planning for infrastructure and internal processes to support the SmartMeters

b. Customer communications and preparations – separately for residential and business customers

c. Implementation of meter changeouts

d. Implementation of web portal

e. Customer information post-changeout

Q. (IF ROLE INCLUDED CUSTOMER CONTACT) What questions were customers asking of you most frequently? Did you feel comfortable with your answers to those questions? Were there any questions that you felt unable to answer adequately --- and why is that?

Exhibit D

Smart Grid Foundation Project

Smart Grid Customer Safeguards

SMART GRID CUSTOMER SAFEGUARDS

The Hawaiian Electric Companies' top priority is the health, safety, privacy and security of their customers, employees and the general public.[1] Therefore, the Companies strive to deliver electric service in a manner that is safe, reliable and environmentally sound. In accordance with the Companies' *Corporate Environmental Principles* (see Attachment 1), the following discussion addresses common concerns or potential questions customers may have about the Companies' proposed Smart Grid technologies that are being implemented in the Smart Grid Foundation Project ("SGF Project"). Any other customer concerns and/or inquiries will be addressed on an ongoing basis through various methods of customer communication and via the customer engagement activities presented in Exhibit C to the accompanying Application.

As discussed in turn below, some of the more common concerns expressed by customers in connection with Smart Grid technologies relate to: (1) whether radio frequency ("RF") signals from smart meters are safe; (2) whether smart meters will increase the risk of meter-related fires at customer premises; and (3) whether transmitting customer usage information over the Smart Grid communications network will affect privacy and security. The Companies have taken additional steps beyond state and federal safety guidelines to address these concerns in the SGF Project.

I. SAFETY GUIDELINES REGARDING RF EXPOSURE

Since Smart Grid was introduced to the United States over 15 years ago, extensive research, both nationally and internationally, has been performed to validate that not only are smart meters compliant with federal standards, the typical exposure levels customers experience pose no risk to human health.[2] It should be noted that smart meter RF waves are much like "radio waves" that have been used for over a century in technologies such as AM/FM/CB radios, VHF/UHF/digital television broadcasting, emergency dispatch services, walkie-talkies, and cellular and wireless devices.

A. RF TECHNOLOGY BACKGROUND

RF became widely used in radio devices in the early 1900s, and then in television transmitting stations which proliferated in the 1950s. More recent uses of RF signals include cell phones, Wi-Fi routers, global positioning system ("GPS") location mapping and satellite radio. In-home sources of RF emissions include baby monitors, microwave ovens, cordless and cellular phones, Bluetooth devices and remote-controlled toys.

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[1] The "Hawaiian Electric Companies" or "Companies" are Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Maui Electric Company, Limited ("Maui Electric") and Hawaii Electric Light Company, Inc. ("Hawaiʻi Electric Light").

[2] See Attachment 2 for Sources for Additional Information on RF Safety from Public Health Agencies.

As illustrated in Figure 1 below, the electromagnetic spectrum encompasses a vast range of frequencies (cycles per second, also referred to as "Hertz" or "Hz").[3] These include very low frequencies such as power lines at 60 Hz, to high-frequency X-rays and gamma rays. While the high-frequency end of the electromagnetic spectrum (from ultraviolet ("UV") rays extending up into X-rays and gamma rays) have sufficient energy to break chemical bonds in biological molecules, the lower end of the electromagnetic spectrum (the frequencies below visible light, including RF) are far less hazardous, and cannot disrupt chemical bonds.

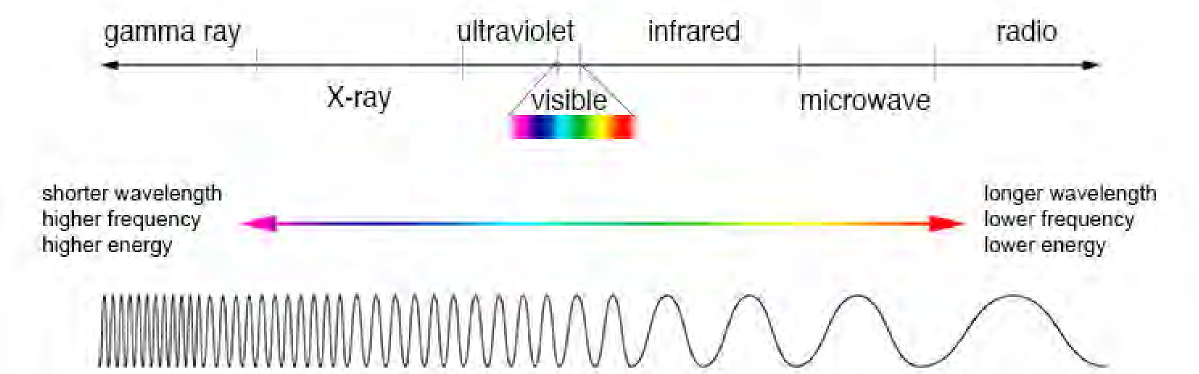

Figure 1

Smart meters are modern electric meters that utilize low-frequency RF signals to send information to the electricity utility. This two-way data sharing enables capabilities such as wireless meter readings, collection of usage data for customers to better manage their energy use, and automated outage detection that allows for quicker restoration times. Myths or misleading claims about smart meters have caused some concerns about the safety of RF. To address such concerns, scientific study from credible third-party health and research organizations has been conducted and there has been no indication in population health statistics that exposure to radio wave technology has caused increases in the incidence of any disease.[4]

B. RF LIMITS AND REGULATIONS

The use of RF technologies is regulated by the Federal Communications Commission ("FCC"), which sets Maximum Permissible Exposure ("MPE") limits on RF exposure levels for the general population. The FCC has developed science-based safety guidelines for RF exposure based upon guidance and recommendations from the U.S. National Council on Radiation Protection and Measurements, the American National Standards Institute ("ANSI"), and the Institute of Electrical and Electronics Engineers ("IEEE"). These standards were recently reviewed by the FCC in 2013, which determined that current scientific findings do not warrant a

[3] See the National Aeronautics and Space Administration (NASA) online discussion of the electromagnetic spectrum, available at http://imagine.gsfc.nasa.gov/science/toolbox/emspectrum1.html.

[4] See the U.S. National Laboratory of Medicine, National Institutes of Health's *Epidemiology of Health Effects of Radiofrequency Exposure*, dated December 2004 available at http://www.ncbi.nlm.nih.gov/pmc/articles/PMC1253668/pdf/ehp0112-001741.pdf.

change in its existing RF exposure limits and policies.[5] The FCC also licenses most RF telecommunications services, facilities and devices (including smart meters).

The MPE limit for smart meters is 600 micro-Watts (“mW”) per square centimeter squared (“cm^2”). For a smart meter in active transmission mode, RF exposure levels at three feet away remain well below (typically 1/300th) the FCC’s MPE limits for RF sources of all types.[6] In other words, the RF from a customer’s contact with a smart meter is exponentially less than other common household devices. In fact, a 2014 testing program on Maui reported RF levels near smart meters (less than a foot away) that were even lower, namely 1/100,000th (0.001%) to 1/7,000th (0.014%) of the FCC allowable public-exposure guideline.[7] Moreover, a May 2015 assessment of the RF levels from the Companies’ smart meters currently installed on O‘ahu reported that the greatest measured RF field at one foot from the meters represented 1/7,500th (0.013%) of the FCC allowable limit for public human exposure.[8]

Figure 2 below illustrates that, among devices that use RF, smart meters emit among the lowest RF energy levels.[9] This is represented in peak power levels, with the impact determined by peak (or average) levels multiplied by the duration of exposure. Since smart meters broadcast for a limited period of time, their total emitted RF energy levels are extremely low.

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[5] See the FCC’s *First Report and Order* in ET Docket 03-137, dated March 27, 2013.

[6] For smart meter RF, the MPE limit is 600 microWatts per sq. cm. (600 µW/cm^2 = 0.6 mW/cm^2 = 6 W/m^2). From Figure 1, “2 µW/cm^2” divided by “600 µW/cm^2” equals 1/300.

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

[8] See Attachment 3 for the May 2015 Richard Tell Associates, Inc. Report of Results of *An Evaluation of Radio Frequency Fields Produced by Smart Meters used by Hawaiian Electric Company – Oahu* (at 2).

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

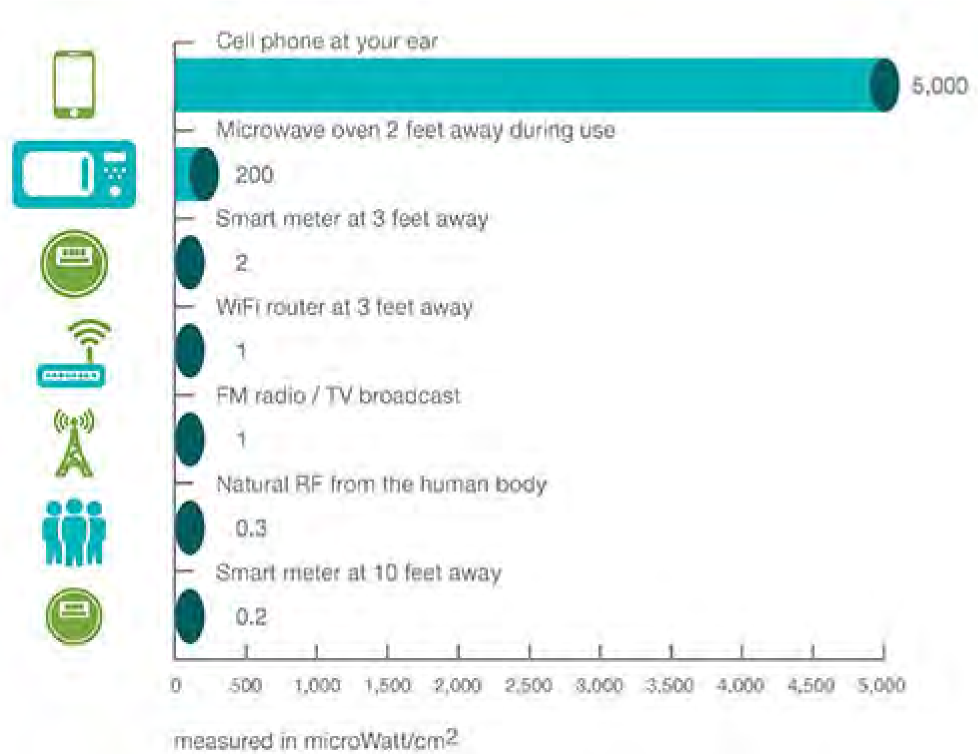

Figure 2

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

Generally, RF exposure guidelines and standards have been developed by interdisciplinary consensus groups, based on the scientific knowledge accumulated both from many years of laboratory work, and on human experience with RF waves (e.g., radio, television, navigation, telemetry, cell phones). In addition to the FCC standards for RF permissible exposure, other agencies – such as the International Commission on Non-Ionizing Radiation Protection ("ICNIRP"),[10] IEEE[11] and Health Canada[12] – have standards that are comparable to the FCC RF standards and other public health agency RF standards around the world (see Attachment 2 to the accompanying Exhibit).

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[10] See the International Commission on Non-Ionizing Radiation Protection, ICNIRP's 2010 Fact Sheet, *On the Guidelines for Limiting Exposure to Time-Varying Electric and Magnetic Fields (1 Hz-100kHz)*, published in Health Physics, dated 2010, available at http://www.icnirp.org/cms/upload/publications/ICNIRPFactSheetLF.pdf.

[11] See the Institute for Electrical and Electronic Engineers' 2006 C95.1-2005 Standards for *Safety Levels with Respect to Human Exposure to Radio Frequency Electromagnetic Fields, 3kHz to 300GHz*, available at http://ieeexplore.ieee.org/xpl/login.jsp?tp=&arnumber=1626482&url=http%3A%2F%2Fieeexplore.ieee.org%2Fstamp%2Fstamp.jsp%3Ftp%3D%26arnumber%3D1626482.

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

Even after many years of research, no credible peer-reviewed scientific studies to date have identified or confirmed any negative health effects from RF exposure at levels below the widely-accepted safety standards. Research findings on potential health effects of RF waves have been assembled and periodically reviewed by numerous independent scientific professional groups composed of research, engineering, medical and public health scientists. The reports of these groups are voluminous, thorough and well-validated.[13]

C. SMART GRID IMPLEMENTATION RF SAFETY MEASURES

As discussed above, the FCC's RF emissions rules are intended to be protective of health and provide an adequate factor of safety. To further address concerns about RF, the Companies are taking a number of additional steps in connection with their SGF Project implementation to assure that safety guidelines and standards are followed, and that relevant information and research is disseminated as widely as possible, including:

- The smart meter devices and RF communications equipment used will have been tested and be required to comply with the limits for a class B digital device,[14] as set forth in Title 47, Part 15 of U.S. Code of Federal Regulations ("CFR");

- The associated electric lines, both underground and overhead, will be in compliance with State construction standards and the National Electrical Code ("NFPA 70") since they will require the installation of additional sensors and increased electrical loads to accommodate the installed smart meters; and

- The Companies are committed to supporting industry, medical and scientific research at the national level, including research efforts of EPRI and the Edison Electric Institute ("EEI"). This includes supporting and monitoring RF studies as they progress; and the Companies will share information with customers and employees including RF information packets offered at no cost, and provide updates on the Companies' websites.[15]

II. FIRE SAFEGUARDS FOR SMART METERS

Replacing existing meters with smart meters does not increase the risk of meter-related fires at customer premises. Further, the Companies will be taking steps to ensure that all meter replacements continue to comply with the Companies' current meter replacement policies, in which all sockets are thoroughly inspected to ensure that meter replacements are safe.

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[13] Sources of additional information on RF safety from public health agencies are provided in Attachment 2.

[14] The FCC defines a "class B digital device" as "a digital device that is marketed for use in a residential environment notwithstanding use in commercial, business and industrial environments." The FCC further defines these devices as "unintentional radiators that generate and use timing signals or pulses at a rate in excess of 9,000 pulses (cycles) per second and uses digital techniques for the purposes of transmission, communication, recording, computations, transformations, operations, sorting, filing, storage, retrieval, or transfer." See http://www.cclab.com/fcc-part-15.htm for additional information.

[15] See the Companies' Smart Grid and Smart Meter information page, available at http://www.hawaiianelectric.com/heco/Clean-Energy/Smart-Grid-and-Smart-Meters.

A. METER FIRE CAUSES AND STATISTICS

Statistics show that fires resulting from any type of electric meter are a rare occurrence. According to the National Fire Protection Agency's 2013 report on home electrical fires, on average, meter fires are attributed to only 1% of reported home electrical fires.[16] Further, Florida Power & Light Company has indicated that despite the more than 4.8 million smart meters installed by that utility, there have been no reports of fires that were determined to have been caused by the smart meters.

Based on the Companies' research, smart meters would not increase the potential risk of a meter-related fire at a customer's premises. Meter-related fires that have occurred are not exclusive to smart meters, but apply more generally to all types of electric meters due to faulty connections or failed components (e.g., loose stab connections) in the customer's meter box. Therefore, one of the best strategies for preventing meter fires (whether "smart" or mechanical) is to properly inspect meter boxes and devices prior to installation and to thereafter ensure that the meters are properly installed. The Companies' inspection and installation procedures of meters are more thoroughly explained below.

B. SMART GRID IMPLEMENTATION FIRE SAFETY MEASURES

To ensure safe and proper inspection and installation of meters, the Companies have established strict meter service rules and installation instructions (see the Companies' *Safety & Health Manual Chapter 16 – Meter Service* provided as Attachment 4 to the accompanying Exhibit) for employees and contractors to follow. Installation, removal and maintenance of all meters will only be performed by properly trained employees and/or contractors who are qualified to check for potential safety issues before meters are exchanged or removed.

Before a meter is removed from a socket, a visual inspection is made of the meter box as well as of the meter device itself. Checks are made to ensure there is no socket damage, loose connection, or foreign object present that could cause a short circuit or flashover. During the SGF Project, if either of these two components is in a deteriorative state, where removal of the meter will cause more damage, then the meter will not be removed. Instead, at that point, the employee/contractor will inform the occupant of the home of the condition of the socket and will make necessary and reasonable repairs to the meter enclosures on the customers' behalf to facilitate the safe installation of smart meters.

C. SMART METER IMPLEMENTATION STANDARDS

All smart meters installed by the Companies will comply with ANSI's C12.10 standard, which confirms mechanical build compliance and accuracy of meter reading.[17] Underwriter's Laboratories ("UL"), which is universally recognized as providing a platform for advancing safety technologies specific to utility devices, recently created a new, voluntary safety standard,

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[16] See Hall, John, R. Jr., *Home Electrical Fires*, published by the National Fire Protection Association Fire Analysis and Research Division, April 2013, at 25.
[17] See https://www.nema.org/Standards/ComplimentaryDocuments/ANSI-C12-10-2011-Contents-and-Scope.pdf.

the *UL 2735 Standard for Electric Utility Meters*,[18] which covers the safety of smart meters. In addition to complying with ANSI standards, UL certification enables utilities to acknowledge and confirm the safety compliance of their installed smart meter devices. The Companies currently require all devices deployed to meet industry specifications set forth by ANSI, and are further investigating the implementation of meters from manufacturers who opt for this voluntary UL certification, as an added layer of safety assurance for customers. The Companies are actively seeking to utilize meter vendors who participate in this extra layer of certification, by incorporating the option for UL certification within the meter selection RFP process as part of the SGF Project (see Attachment 1 of Exhibit E to the accompanying Application).

III. DATA PRIVACY AND SECURITY SAFEGUARDS

Customer information privacy and grid security are and will continue to be a high priority for the Companies as they deploy the SGF Project throughout their service territories. A thorough evaluation of how Smart Grid will affect the Companies' current cybersecurity and privacy standards is further detailed in Attachment 5 to the accompanying Exhibit.

The Companies have developed, maintain and continue to improve policies and procedures to safeguard customer information. They have approached customer concerns on privacy and security from a proactive and flexible platform, specifically designed to address the risk of outside intrusion into the Companies' network.

The rules and safeguards the Companies currently have in place to protect customer privacy will evolve as new customer options become available through the use of Smart Grid technologies. Customer information is confidential and will not be shared with third parties unless needed for business operations, authorized by the customer, or as required by law or regulation. The Companies do not sell, rent or lease personal information or personally identifiable information, without the customer's consent; nor will personal information be used for anything other than to provide customer options, ensure customers are being billed accurately or provide safe and reliable electrical service.

Smart meters do not store or send any customer-identifying information. Customer energy usage information transmitted between smart meters and the Companies is encrypted using U.S. government-approved and recommended standards. These standards are regularly reviewed to remain current with industry and government security protocols.

Similar to what is used by governments, the military and private businesses such as commercial banks, the Companies and the smart meters communicate over a private network, not through the open Internet. This network is protected by strong authentication and authorization controls.

As an added level of security, the Companies' and their partners have conducted security planning and testing of smart meters, and have developed security processes and procedures, many of which were adapted from the banking and defense industries.

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[18] See *New UL 2735 Electric Utility Meter Standard Ensures Safety and Performance*, available at http://www.metlabs.com/blog/tag/ul-2735.

The addition of new information technology and two-way communications systems derived from Smart Grid technologies into the Companies' distribution networks and operations will require evolving cybersecurity measures. These assessment measures will be ongoing and will work to continually evaluate possible risks that have the potential for any level of threat to information privacy or grid security, as noted above. The Companies are dedicated to ensuring that the information transmitted over their communication devices, such as the smart meters, access points and relays, stays safe, secure and confidential. The Companies will also continue to meet the cybersecurity and privacy standards they have in place to ensure customer confidence throughout the deployment phase of the SGF Project, and beyond.

IV. CONCLUSION

As the Companies move forward with the deployment of Smart Grid technologies throughout their service territories in Hawaiʻi, there will be ongoing community outreach and customer communication events geared directly towards addressing customer concerns. The Companies will also be proactive in monitoring new and developing scientific research relating to the health and safety of RF emissions. Further, the Companies will continue to address potential device safety, privacy, and cybersecurity risks and issues proactively, ensuring that their systems meet applicable industry standards. The Companies will also continue to ensure that customers are appropriately notified should there be changes in the Companies' Privacy Policy Notice.[19]

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[19] Available at http://www.hawaiianelectric.com/portal/site/heco/privacypolicy.

Attachment 1

Smart Grid Foundation Project

Exhibit D

The Hawaiian Electric Companies' Corporate Environmental Policies

ENVIRONMENTAL PRINCIPLES

Hawaiian Electric's commitment to safety, health and the environment.

To emphasize our commitment to consider the safety and health of the public and the environment in our business decisions, we at Hawaiian Electric Company have adopted environmental principles governing the conduct of our companies. In keeping with this commitment, we will:

- Conduct affairs in a manner that protects Hawai'i's unique historic and cultural heritage.
- Protect the air, land and water resources where we operate by limiting the generation of wastes and discharge of pollutants.
- Take reasonable measures to address the effects that our facilities and operations may have on protected seabirds and other protected species.
- Prepare for environmental emergencies that may arise from our operations and act promptly to minimize environmental damage.
- Conserve natural resources in all our pursuits and encourage our customers to use electricity and other forms of energy wisely and efficiently.
- Support research on safety, health and environmental effects associated with company operations.
- Advise the public on how to use our products safely and inform them of any known potential health or environmental risk associated with our operations.
- Be a good neighbor in the communities in which we do business and respond in a timely manner to inquiries and complaints about the environmental effects of our operations.
- Work cooperatively with citizen and government organizations to identify emerging environmental problems and develop realistic, cost-effective solutions to protect the safety and health of Hawai'i's people and the environment of our state.

Hawaiian Electric

Attachment 2

Smart Grid Foundation Project

Exhibit D

Sources of Additional Information on Radio Frequency Safety from Public Health Agencies

SOURCES OF ADDITIONAL INFORMATION ON RADIO FREQUENCY SAFETY FROM PUBLIC HEALTH AGENCIES

A number of public health agencies have examined, and periodically re-examine, the issue of radio frequency ("RF") waves and how they interact with living organisms. These agencies provide both summary opinions and comprehensive reviews of the research literature that capture the state of the science. The following examples provide some of the summary conclusions, and also additional resources for independent investigation on RF safety:

- **American Cancer Society** ("ACS", 2014) "Most animal and laboratory studies have found no evidence of an increased risk of cancer with exposure to RF radiation. A few studies have reported evidence of biological effects that could be linked to cancer. Studies of people who may have been exposed to RF radiation at their jobs (*e.g.*, people who work around or with radar equipment, service communication antennae or operate radios) have found no clear increase in cancer risk." Available at http://www.cancer.org/cancer/cancercauses/radiationexposureandcancer/radiofrequency-radiation.

- **Committee on Man and Radiation** ("COMAR") Technical Information Statement on Radiofrequency Safety and Utility Smart Meters. Published in the journal "*Health Physics*" Volume 108, pages 388–391; 2015. Summary text: "The low peak power of Smart Meters and the very low duty cycles lead to the fact that accessible RF fields near Smart Meters are far below both U.S. and international RF safety limits whether judged on the basis of instantaneous peak power densities or time-averaged exposures." Available at www.health-physics.com; see also http://hps.org/hpspublications/articles/rfradiation.html.

- **European Union** ("EU") public health statement on RF [including Smart Meters]. Available at http://ec.europa.eu/health/scientific_committees/emerging/docs/scenihr_o_041.pdf ("smart meters would make only minor contributions to the total background RF radiation level inside a home, which is in any event tiny in comparison to accepted safety limits."); see also http://ec.europa.eu/health/scientific_committees/docs/citizens_emf_en.pdf (The EU citizens' summary states: "IS EMF EXPOSURE DANGEROUS FOR YOUR HEALTH? The results of current scientific research show that there are no evident adverse health effects if exposure remains below the levels set by current standards.").

- **Health Canada**, Royal Society of Canada, 2012, available at http://www.hc-sc.gc.ca/hl-vs/iyh-vsv/prod/meters-compteurs-eng.php ("As with any wireless device, some of the RF energy emitted by smart meters will be absorbed by anyone who is nearby. The amount of energy absorbed depends largely on how close your body is to a smart meter. Unlike cellular phones, where the transmitter is held close to the head and much of the RF energy that is absorbed is localized to one specific area, RF energy from smart meters is typically transmitted at a much greater distance from the human body. This results in very low RF exposure levels across the entire body, much like exposure to AM or FM radio broadcast signals. . . . Based on this information, Health Canada has concluded that exposure to RF energy from smart meters does not pose a public health risk.”).

- **International Agency for Research on Cancer** (“IARC”, 2013), *Non-ionizing radiation, part 2: radiofrequency electromagnetic fields*, Volume 102, available at http://www.iarc.fr/en/media-centre/pr/2011/pdfs/pr208_E.pdf; see also http://monographs.iarc.fr/ENG/Monographs/vol102/mono102.pdf

  In 2011, the International Agency for Research on Cancer (“IARC”) classified RF from cell-phone handsets as “2B” or “possibly carcinogenic to humans,” which refers to the circumstances where there is limited-to-inadequate evidence of carcinogenicity in humans and limited-to-inadequate evidence in experimental animals. The IARC Working Group determined that, “There is limited evidence in humans for the carcinogenicity of radiofrequency radiation. Positive associations have been observed between exposure to radiofrequency radiation from *wireless phones* and glioma, and acoustic neuroma.” “Radiofrequency electromagnetic fields are possibly carcinogenic to humans (Group 2B).”[1] “There was, however, a minority opinion among the Working Group members that current evidence in humans was inadequate, thus permitting no conclusion about a causal association.” Notably, because IARC’s 2B classification did not quantitatively analyze wireless phone risk, it did not suggest changes in RF guidelines and standards for safe exposure levels.

- **International Commission on Non-Ionizing Radiation Protection**. (“ICNIRP”, 2009). “ICNIRP’s statement on the ‘Guidelines for limiting exposure to time-varying electric, magnetic, and electromagnetic fields (up to 300 GHz).’ Health Physics 97(3):257-8”, available at http://www.icnirp.org/en/publications/article/hf-review-2009.html (“RF fields are used in a variety of technologies, most widely for communication purposes (e.g., mobile phones, base stations, Wi-Fi, radio, TV, security devices), and also in medicine (e.g., Magnetic Resonance Imaging (MRI) equipment) and for heating purposes (e.g., microwave ovens). Acute and long-term effects of RF exposure below the thermal threshold have been studied extensively without showing any conclusive evidence of adverse health effects.”).

- **The Scientific Committee on Emerging and Newly Identified Health Risks** (“SCENIHR”) has prepared a March 2015 fact sheet which is based on the independent analyses of the science: “Potential health effects of exposure to electromagnetic fields (EMF).” Several levels of summarization are available at: http://ec.europa.eu/health/scientific_committees/consultations/public_consultations/scenihr_consultation_19_en.htm;

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[1] IARC uses the “possibly carcinogenic” category when talking about both cell phones and power-line magnetic fields (“EMF”), and the IARC category 2B includes “possible carcinogens” such as coconut oil, gasoline, diesel fuel, fuel oil, power-line EMF, “carpentry and joinery,” coffee, carbon black (car tires), car-engine exhaust, surgical implants, talc-based body powder, iron supplement pills, mothballs, nickels, pickled vegetables, safrole tea, titanium dioxide (sunscreen), chloroform and many other substances. Available at http://monographs.iarc.fr/ENG/Classification/ClassificationsGroupOrder.pdf.

http://ec.europa.eu/health/scientific_committees/emerging/opinions/index_en.htm; and http://ec.europa.eu/health/scientific_committees/emerging/docs/scenihr_o_041.pdf.

Some summary text is as follows: "The results of current scientific research show that there are no evident adverse health effects if exposure remains below the levels set by current standards." "Thorough examination of all pertinent, recent data has not produced any conclusive evidence about EMF being dangerous, which is reassuring. However, further research should be conducted, particularly as pertains to very long-term exposure and potential risks of exposure to multiple sources."

- **World Health Organization** ("WHO", 2014). "Electromagnetic fields and public health: mobile phones" Fact Sheet 193 available at http://www.who.int/mediacentre/factsheets/fs193/en/. Fact Sheet 193 states, "A large number of studies have been performed over the last two decades to assess whether mobile phones pose a potential health risk. To date, no adverse health effects have been established as being caused by mobile phone use."

Attachment 3

Smart Grid Foundation Project

Exhibit D

An Evaluation of Radio Frequency Fields Produced by Smart Meters Used by Hawaiian Electric Company

RICHARD TELL ASSOCIATES, INC.

An Evaluation of Radio Frequency Fields Produced by Smart Meters Used by Hawaiian Electric Company

May 4, 2015

Prepared for

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An Evaluation of Radio Frequency Fields Produced by Smart Meters Used by the Hawaiian Electric Company

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An Evaluation of Radio Frequency Fields Produced by Smart Meters Used by the Hawaiian Electric Company

Summary

This study found that the Hawaiian Electric Company smart meter radiofrequency (RF) emissions relative to potential exposure of the public, or Hawaiian Electric Company workers, are very small in comparison to the applicable Federal Communications Commission (FCC) limits for exposure. This finding of compliance with the FCC Maximum Permissible Exposures (MPEs) holds true whether or not the peak measured fields are adjusted for meter duty cycles and spatial averaging (as implicit in determining compliance with the FCC rules) or any other factor that reduces RF fields such as the construction materials of homes, or whether the meters exist in a large group or whether individuals are outside near the smart meter or inside their residence. The strongest fields were, as expected, at the closest distance at which measurements were performed, i.e., 1 foot or 0.3 meters. When viewed from the perspective that the FCC MPE includes a safety factor of 50 relative to the threshold for adverse health effects, the potential exposure of persons near the Hawaiian Electric Company smart meters not only complies by a wide margin with the MPE limit but will be as a minimum 376,000 times less than that value associated with adverse health effects as defined by the FCC exposure limits.

Smart meter RF emissions represent but one source of potential public exposure but because of the low power at which smart meter transmitters operate, the ambient RF fields are relatively weak. Other example sources of RF exposure include radio and television broadcasting, microwave ovens and wirelessly connected devices such as wireless routers used in homes for distributing Internet connectivity and laptop computers. RF fields exist throughout the environment and are produced by a multitude of different sources. The contribution of smart meters to overall potential exposure is typically small but will vary, depending on location and proximity to other RF sources.

Widespread deployment of electric “smart meters” across the United States has stimulated questions by the public about the safety of exposure to the RF fields produced by the low power (1 watt) transceivers contained within the meters. Smart meters make use of wireless digital communication technology to transmit customer electric energy consumption data to the electric utility. This report describes a study to determine the potential exposure of the public to the RF fields produced by smart meters being deployed by Hawaiian Electric Company.

The smart meters currently being used by Hawaiian Electric Company make use of frequencies in the license-free band of 902-928 MHz and employ frequency hopping spread spectrum (FHSS) technology for transmission of data on electric energy usage.

RF Emissions of Smart Meters Deployed by Hawaiian Electric Company

Electric smart meters are deployed in so-called mesh networks wherein each end-point meter (a smart meter) installed on a home or business can wirelessly communicate with other neighboring meters as well as data collection points referred to as access points. Each access point (AP) can serve some hundreds of end-point meters and send the electric energy consumption data received from the meters back to the electric utility company via a separate, wireless wide area network (WWAN).

During March 2-4, 2015, on-site measurements at several residential and commercial locations in the Hawaiian Electric Company service territory were conducted to determine the strength of the RF emissions very close to the meter as well as within homes equipped with smart metes. The study also examined the composite RF field environment where smart meters were aggregated in banks of meters at two apartment/condominium complexes and a commercial building. Measurements of the short-term duty cycles for individual smart meters and a bank of smart meters were accomplished as well as ground level field measurements in the vicinity of elevated access point (AP) and a relay installations.

Most of the measurements revolved around application of a spectrum analyzer based instrument (Narda model SRM-3006) that makes use of an attached probe/antenna and can indicate measured RF field magnitudes directly as a percentage of the MPE values of the FCC. The detection equipment contains three mutually orthogonal probe elements that results in an isotropic, spatial response to all polarization components of the RF field. The instrument also contained a “scope” option that permitted measurement of smart meter signal waveforms (duration of the emitted bursts of signals). The sensitivity of the instrument and ability to measure the intensity of the RF field on specific frequencies were essential to the success of the measurement program.

Directly in front of the smart meters included in these measurements, the greatest peak RF field at one foot from the meter was found to be 7.1% of the FCC’s MPE for public exposure. The measured RF field decreased quickly with increasing distance from the meter. For example, at a distance of five feet, the field was measured to be less than 0.47% of the MPE. When adjusted for the amount of actual transmit time of the meter, the greatest time-averaged RF field power density at one foot from the meter was 124 times less than the measured peak value. It was found that spatial averaging of the smart meter RF field across the body dimension, consistent with FCC rules on human exposure, resulted in values approximately 23.2% of the spatial maximum value. This means that the greatest measured RF field at one foot from the meters included in these measurements, when adjusted for both time and spatial averaging, represented 0.0133% of the human exposure limit set by the FCC for members of the public.

Banks of smart meters, such as found on some apartment buildings, do not result in greater peak values of RF fields than those produced by an individual meter but can exhibit higher average field magnitudes due to the multiple meter operation. However, because the duty cycles of endpoint meters are so small, the time-averaged RF fields from large banks of meters are not capable of resulting in exposure that would exceed the FCC limits. Hence, in terms of both instantaneous peak (signal burst maximum) and average values, the RF fields comply by a wide margin with the FCC MPEs.

Exposure of individuals in their smart meter equipped homes is commonly orders of magnitude less than that which would occur for an individual standing immediately adjacent to and in front of a meter. Within any of the homes included in this study, the greatest smart meter related peak RF field was equivalent to 0.013% of the FCC MPE for public exposure.

No material difference was found for the peak RF fields associated with residential or commercial meters, whether individual or when installed in a bank of multiple meters.

Potential exposure to Hawaiian Electric Company smart meters is constrained by the low power of the transmitter and low antenna gain. A one-watt transmitter produces only limited RF field power density.

Introduction

This report documents a study of radiofrequency (RF) emissions associated with operation of electric smart meters deployed by the Hawaiian Electric Company (Hawaiian Electric Company). Hawaiian Electric Company has deployed approximately 5,060 smart meters in its service territory on the island of Oahu as part of a demonstration project to evaluate smart meter technology and to assist Hawaiian Electric Company in determining the best way forward toward full implementation of this element of their smart grid program. A proliferation of smart meters across the nation, as a component of the so-called smart grid initiative in the United States, has raised the question among some in the public of how the RF emissions of these new technology meters compare with limits that have been set for safe human exposures. Recent studies have determined that the low power of the radio transmitters inside the meters results in only low level RF fields that comply with Federal standards, generally by wide margins [1, 2, 3]. Nonetheless, this relatively new technology that includes the production of brief but numerous pulses of RF energy and the sheer number of emitters (one on each home and business) continues to elicit questions regarding smart meter emissions and has influenced a more in-depth examination of smart meters as used by Hawaiian Electric Company in their demonstration project.

The study reported here was focused on evaluating RF emissions produced by these demonstration project smart meters and how those emissions compare to the applicable exposure limits promulgated by the Federal Communications Commission (FCC). The smart meters included for measurements are manufactured by Landis+Gyr

(Alpharetta, GA) and contain low power (nominally one watt) transceivers that provide wireless digital communications for transmitting electric energy consumption and other meter status data between end point meters on residences and businesses and Hawaiian Electric Company . Access points (APs) act as data collection points with which end point meters interact during communication. The radio transceivers are manufactured by Silver Spring Networks, Inc. (Redwood City, CA) and communicate within the FCC designated license free band of 902-928 MHz as part of an RF local area network (LAN). A second radio in the meters consists of a Home Area Network (HAN) device that operates in the 2.4-2.5 GHz frequency band for communication with in-home displays as well as smart thermostats and other controllable devices. This type of wireless technology is part of so-called Advanced Metering Infrastructure (AMI) being implemented across the country. In the Hawaiian Electric Company demonstration project, the HAN radio was disabled and not active at the various measurement locations which were a part of this study.

This study examined the strengths of the RF fields emitted by smart meters with attention to both the instantaneous peak and average values of RF field power density. The work also included measurements of the duration of the brief emissions and the amount of time that the meters actually transmit[1]. Effort was made to identify the maximum amount of transmitter activity that might occur during smart meter operation.

Basic Meter Specifications

This report describes measurements of RF fields produced by the smart meters presently deployed by Hawaiian Electric Company as part of their smart grid pilot study. The Landis+Gyr meter is shown in Figure 1. These meters contain low power radio transmitters that have the capacity of operating on two different bands of frequencies including the 902-928 MHz and 2.4-2.5 GHz license free bands[2]. The transceiver carries the FCC ID number OWS-NIC714. Based on certification reports filed with the FCC, Table 1 provides the maximum transmitter output powers, antenna gains and maximum effective isotropic radiated power (EIRP[3]) for the Silver Spring Networks radio. The transceiver employs frequency hopping mesh network radios for both the 900 MHz RF LAN and 2.4 GHz Zigbee Home Area Network (HAN) radio. At the time of the study, Hawaiian Electric Company had not implemented use of the HAN radios in the deployed smart meters.

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[1] This is related to a term called duty cycle, described later in this report.
[2] A license free band is a specific range of frequencies in which strict limitations on transmitter power are imposed.
[3] EIRP is the product of the power delivered to the antenna and the gain of the antenna in a specific direction. For example, if the antenna gain is 3 dB in a particular direction, it results in the EIRP being twice the value in that direction compared to an isotropic radiator.

RF Emissions of Smart Meters Deployed by Hawaiian Electric Company

Meters are deployed in a mesh network and can automatically establish network routes that permit communication with an appropriate access point. Each meter can store several route tables within its digital memory, allowing it to optimally connect with an appropriate neighboring meter for relaying of data in the event that an alternative network connection does not work. For instance, if a particular propagation path between an endpoint meter and the access point becomes broken (e.g., due to signal blockage), alternative paths are automatically adopted to successfully communicate with the appropriate access point. In this sense, mesh networks are sometimes described as “self-healing” meaning that communication between any given meter in the network and its associated access point can be achieved through the meter’s interaction with other meters within the network. This concept actually allows a meter that cannot directly reach an access point (the access point is not directly within transmission range) to work through other meters in the network to get its message through. This feature of mesh networks forms a very powerful capability in terms of network communications and provides for considerable reliability in terms of the network’s ultimate purpose.

Table 1. Selected specifications for the Landis+Gyr smart meters deployed by Hawaiian Electric Company , the FCC ID number, operating frequency ranges and transmitter output powers indicated in associated certification reports to the FCC.

	RF LAN	HAN
FCC ID	OWS-NIC714	OWS-NIC714
Transmitter power output	+29.6 dBm	+22.7 dBm
Antenna gain	4 dBi	1 dBi
Maximum EIRP	+33.6 dBm (2,291 mW)	+32.7 dBm (1,862 mW)
Frequency range	902-928 MHz	2.4-2.5 GHz

The indicated antenna gains in Table 1 are the maximum values specified by Silver Spring Networks; antenna gains in directions other than the main beam would be less, resulting in less transmitted power density.

RF Emissions of Smart Meters Deployed by Hawaiian Electric Company

Figure 1. Photograph of the Landis+Gyr smart meter deployed by Hawaiian Electric Company .

Assessing Potential Exposure to Smart Meters

Human exposure to RF fields is most commonly characterized in terms of incident power density typically specified by the unit milliwatt per square centimeter (mW/cm^2). For example, the exposure limits promulgated by the FCC are represented by different values of power density that vary with frequency[4]. Several factors determine the magnitude of power density that can be produced by any source at a given point. These include the amount of power delivered to the antenna (the number of watts), the directional pattern of the antenna in the source, the mounting location of the source relative to where an individual may be and the duty cycle of the source (i.e., a measure related to the percentage of time that the transmitter actually transmits an intermittent signal). Smart meters operate by sending digital messages via brief pulses of RF energy, typically in the range of 2 to 12 milliseconds (ms) in duration. These messages allow for the meter to remain appropriately connected within the wireless network, to relay data from neighboring meters, when needed, and to transmit electrical usage data. While these pulses can occur relatively frequently throughout the day, they commonly amount to less than one percent of the time. As an example, for a meter exhibiting a duty cycle

[4] The FCC MPE varies with frequency because the human body absorbs RF energy differently at different frequencies. The MPE is most stringent in the frequency range of about 30-300 MHz wherein the body absorbs RF energy most efficiently.

of one percent, this is equivalent to approximately 14 minutes distributed throughout the day that the smart meter transmitter actually emits a signal.

In the case of the smart meters used within Hawaiian Electric Company , as currently operated, meters report electrical usage data to the company on an hourly basis each day (this could change with further deployment of the AMI technology throughout Oahu and may evolve to only four to six times per day). Hence, the duty cycle associated with most smart meters is a few percent, and in most cases, less. The duty cycle can vary throughout a given day from time-to-time, depending on network performance and a meter's position in a network relative to the other meters within that network. This complex variability in meter operation from hour-to-hour and from day-to-day suggests that a statistical approach to evaluation of operation over a large sample of meters is the only way to assess the whole range of meter activity for a smart meter network.

For evaluating compliance with RF exposure standards, the time-averaged value of plane wave power density is usually the most fundamental aspect of specifying exposure. Existing RF exposure standards specify averaging times of either six minutes, normally applied to assessing occupational exposures, or 30 minutes, usually applied to exposure assessment for members of the general public. Further, the exposure limits are specified as spatial averages over the cross section area of the body[5]. Hence, a proper interpretation of compliance means that one determines the maximum instantaneous peak value of RF power density, multiplies it by the fractional amount of time that the RF field is actually present (the duty cycle which varies between 0 and 1) and then multiplies this quantity by a factor that relates the body average value to the maximum value (spatial averaging). This is the general approach used in this study for assessing compliance.

The antennas contained within smart meters are not omnidirectional, although the pattern of emitted field is commonly very broad and approximates the pattern of an omnidirectional source; there is a preferred direction in which the strongest RF field is transmitted, usually away from the meter with directions of reduced RF fields usually to the sides and almost always to the rear of the meter. When a wireless smart meter is installed in a meter socket (typically in the electric service panel on a home), the metal electrical box that contains the meter socket interacts with the RF fields to distort what the antenna pattern would in the absence of the meter box. The meter box can also provide significant shielding in directions to the rear of the meter, generally in directions toward the home on which the meter is installed, such that interior RF field strengths (or power densities) will be significantly less than at equivalent distances but in front of the meter.

[5] In practice, spatial averages are normally determined from measurements along a vertical line representing the height of a person.

The signal pattern of the smart meter antenna determines the intensity of the transmitted RF field in both the azimuth (horizontal) plane and elevation (vertical) plane. The significance of this is that the RF fields found near smart meters are highly non-uniform due to the metal components of the meter itself and the metal box within which it is normally mounted. This results in exposure of the body that is also highly non-uniform with the greatest RF field being at the meter itself. Since exposure limits are based on spatial averages over the body as well as time averages over time, compliance assessments normally include a measure of the spatial variation of field along the vertical axis of a person standing near the meter. This means that the body averaged value of exposure is always something less than the spatial peak value that might occur directly in front of the meter where the field is most intense. Nonetheless, for purposes of the evaluation reported here, measurements of RF fields at the height of the meter were obtained for exterior locations near the meter. Limited data were also obtained to document the variation in field over a distance from ground level to six feet (1.83 m) above ground so that spatial average values of field could be estimated from the measured peak values of fields.

Because the transmitted fields from smart meters can exhibit such a strong dependency on direction away from the meter, mounting locations will strongly influence the exposure values for a person near the meter. If the meter is mounted relatively high above ground, most of the body may be exposed to only very weak RF fields. If the meter is mounted lower, more of the body may be subjected to the most intense emissions since the body may intercept most of the transmitted fields within the elevation plane. The issue of how much more localized exposure of the body is when compared with the average over the entire body dimension depends strongly on the distance between the meter and a person; the greater the distance from the meter, the more uniform the field across the body will be but, at the same time, the weaker the field will also be, simply because of the rapid decrease in RF field with distance.

The RF exposure limits adopted by the FCC are also based on averages over time. For the smart meters used by Hawaiian Electric Company , this is determined by the duty cycle of their emissions, as discussed above, and on occupancy of areas near the meter. Closer distances can result in greater exposure while farther distances result in lower exposures. In summary, assessing potential exposure to the Hawaiian Electric Company smart meters was accomplished by measurement of the instantaneous peak RF fields near the smart meters and, then, adjustment of the peak value by the duty cycle of the meters to obtain the relevant time-averaged value of field and, finally, adjustment for how the RF field from a meter varies across the height of a person standing immediately adjacent to the meter.

RF Exposure Limits

In the United States, the controlling limits for human exposure are those adopted by the FCC [4]. FCC maximum permissible exposures (MPEs) apply to FCC licensees but despite the fact that the subject smart meters operate in license-free bands, the FCC limits have historically been used by the FCC for evaluating RF exposure to smart meters even though the user, in this case Hawaiian Electric Company , is not a licensee of the FCC. In fact, the internal radio transmitters in all smart meters are included in test reports provided by the manufacturer to the FCC and are commonly available via the FCC's equipment authorization data base. Table 2 summarizes the MPEs from the FCC applicable to the emission frequencies associated with the Hawaiian Electric Company smart meters.

It is relevant to note that the exposure limits asserted as safe for continuous exposure of the public are not set at the point just beyond which adverse biological effects might be expected. Rather, the limits were derived from experimental data on laboratory animals and the MPE for public exposure was set with a safety factor of 50, being 50 times lower than the actual threshold determined for adverse effects. Hence, compliance with the MPE means that the exposure is at least 50 fold less than the adverse effects threshold.

Table 2. FCC MPEs pertinent to the Hawaiian Electric Company smart meter RF fields over the range of nominal relevant frequencies. MPE values are in terms of power densities averaged over 6 minutes for occupational exposure and 30 minutes for exposure of the general public. Values given are in terms of time averaged and spatially averaged values.

Frequency	902-928 MHz		2.4-2.5 GHz	
	General public	Occupational	General public	Occupational
MPE (mW/cm^2)	0.601-0.619	3.01-3.09	1.00	5.00

Compliance with the FCC MPEs for general public exposures calls for time averaging so long as the modulation of the field is "source based", i.e., inherently a consequence of the way the source operates. Examples include the pulsed RF fields produced by radars, the typically intermittent operation of two-way mobile and portable radios and, in this case, the normal intermittency of smart meter emissions [5]. For situations in which the continuous RF field exceeds the MPE, however, the FCC has taken the position that time averaging is not permissible for showing compliance with the exposure rules. This is based on the conservative assumption that compliance would only be achievable if an individual physically moved about to result in a variable exposure level that could, upon averaging, be reduced below the MPE. Thus for smart meter emissions, a comprehensive determination of compliance with the FCC exposure rules requires assessing the average RF field across the dimensions of the body and the average over time. In practice, however, and as found in virtually all of the certification reports filed with the FCC for smart meter emissions by manufacturers, a simplifying assumption is made that if the maximum, instantaneous field[6], without inclusion of time- or spatial-averaging, is compliant with the MPE, then no further evaluation is necessary. In this investigation, the issues of how duty cycle and spatial averaging can affect exposure assessment are addressed; for both of these factors, exposures will be found that are less than maximum, instantaneous field values. The RF field measurement values documented in this report are expressed in terms of a percentage of the public MPE; i.e., a value of 100% represents the exposure limit. Values exceeding 100% are not compliant with the limit and values less than 100% are compliant.

The MPEs listed in Table 2 are based on limiting the underlying basic restriction on RF energy absorption within the body, as a whole, and on local tissue absorption. The energy absorption rate is referred to as the specific absorption rate (SAR) which is expressed in the unit watts per kilogram (W/kg) of tissue. The FCC MPEs, for general public exposures, are based on a whole-body averaged (WBA) SAR limit of 0.08 W/kg with a local, peak SAR of 1.6 W/kg averaged over any one gram of tissue (defined as a tissue volume in the shape of a cube) except for the extremities (hands, wrists, feet and ankles) in which a local SAR of 4 W/kg averaged over any 10 grams of tissue is permitted. For occupational exposures, the FCC MPEs correspond to a WBA SAR of 0.4 W/kg with a local, peak SAR of 8 W/kg averaged over any one gram of tissue except for the extremities in which the SAR limit is 20 W/kg averaged over any 10 grams of tissue.

In summary, while it is correct that if the maximum, instantaneous peak power density is less than the applicable exposure limit, then compliance is assured, in this study, additional work was conducted to arrive at a more exact determination of exposure. The matters of smart meter emissions typically being present for only a small percentage of all time and the RF field being spatially variable over the body dimensions were examined in the context of compliance.

Technical Approach Used in this Project

RF field measurements were performed by capturing the instantaneous peak power density of the smart meter emissions by observing the signal over multiple transmissions to insure detection of the greatest value of RF field. To increase the activity of the smart meters, thereby enhancing the ability to capture the brief, emitted signals, a field service unit (FSU) was used to "ping" the meter, causing the meter to transmit pulses on a repetitive basis. To facilitate the measurement process, a Hawaiian Electric Company Field Service Representative made use of an FSU to transmit a signal to the smart meter under investigation, causing it to respond with its signal. To cause a relatively rapid repetition of smart meter signals for measurement, the FSU in

[6] The term instantaneous refers to the absolute peak magnitude of the RF field in the time domain, similar to the peak field strength of a radar pulse.

conjunction with a laptop computer, was used to ping the smart meters in a repetitive fashion typically lasting at least 10 seconds at a time. By keeping the equipment used to ping the meters at a reasonable distance (commonly several hundred feet) from the smart meter, it was possible to isolate and detect just the response of the smart meter without any interference from the signal pinging the meter.

Measurements of peak RF fields were conducted at a variety of smart-meter equipped single-family residences, commercial facilities and an apartment and condominium. At the apartment and condominium, measurements were performed both directly in front of the meter(s) and within the home. The approach used for individual meters was to position the measurement probe directly in front of the meter at different distances as illustrated in Figure 2. The probe was typically moved slowly up and down along a vertical line in front of the subject meter. This process tended to increase the opportunity to capture RF fields being emitted at different elevation angles relative to the meter that may be stronger than that directly in front of the meter. When wireless network radios are installed inside of electric power meters, the resulting transmitting pattern is inherently distorted by the meter construction itself. This means that the emitted RF field will generally be different in different directions from the meter face. However, using a standardized measurement technique (directly in front of the meter) can improve the reliability of exposure estimates at a known location in front of the meter.

Figure 2. Measurement of smart meter fields at site 10.

Figure 3 illustrates the approach of performing measurements at site 7 where a bank of six meters is enclosed in an electrical closet adjacent to different condominiums. The measurement probe was held at fixed distances from the frontal plane of the meters and swept slowly in an up and down motion to ensure capture of the maximum field. When measuring in front of a bank of meters, where it was feasible, the probe was also slowly swept horizontally across a plane at a fixed distance from the meters to maximize the opportunity for the instrument to acquire the greatest peak RF field emitted by any of the meters in the bank. For large banks of meters, the probe was carried as the observer walked back and forth in front of the bank with the measurement probe held in front of the body and simultaneously moving it up and down to sweep out the frontal plane of the meter bank.

Figure 3. Illustration of the measurement of RF fields at a bank of six meters at site 7.

Measurements were also conducted at the location of one of the Hawaiian Electric Company relays (site 11) and one of the access points (site 12). All measurements were performed within the cities of Honolulu and Pearl City, HI, during March 2-4, 2015.

As described above, determining smart meter duty cycles is challenging because of the variability in meter emission activity. The approach used in this study was to identify smart meters that, due to their hierarchy in the mesh network, were presumed to be the most likely to pass data onto an access point from other meters. At several measurement locations, measurements of RF fields were obtained by use of a "scope mode" on the instrumentation, allowing the determination of the field duty cycle. Continuous measurements over 30-minute periods (and in a few instances at shorter durations) were used for determining the duty cycle. The results of these measurements were used to adjust measurements of instantaneous peak power densities to appropriately time-averaged values for comparison with the FCC MPEs.

At one location, RF fields in front of a smart meter were measured as a function of height above ground to assess how the spatially averaged value of RF field compares to the spatial maximum field. Table 3 summarizes the various measurement scenarios encountered during the study.

Table 3. Summary of various measurement scenarios during project.

Number of sites	Description	Meter configuration
5	Single family residences	Exterior, single meter
2	Apartment/condominium	Interior and exterior, banks with 6 and 27 meters
2	Commercial sites	Exterior, single meters
1	Commercial site	Exterior, bank with 19 meters/14 active
1	Relay site	Exterior, overhead mounting
1	Access point	Exterior, overhead mounting

Field measurements were also taken at sites where a relay and access point (AP) were installed. Both the relay and AP are mounted overhead (at 25 feet or greater) on electric power poles along city streets (see Figures 4 and 5 showing the relay and AP respectively). A relay device is used where there is a need to enhance wireless connectivity between various end point meters and an AP. The AP represents the device collecting data from many meters and passing it on Hawaiian Electric Company via a wireless wide-area network (WWAN). Generally, in the Hawaiian Electric Company demonstration project, most endpoint meters are able to wirelessly connect directly to one of six APs currently installed at various locations throughout the Hawaiian Electric Company network by establishing a contact without any relaying of data via other network meters or a dedicated relay device. Nonetheless, there are always an inherent number of meters that may have difficulty in communicating directly with an AP. This, in turn, leads to more data throughput at certain end point meters that have solid connectivity with an AP and are within reach of the other meters that are having difficulty in connecting. This means that such endpoint meters that provide this communications assistance are expected to exhibit greater duty cycles since they will be normally interacting with an AP like other meters on the wireless network but, in addition, will be transmitting information from other meters that are not able to directly connect with the AP.

Figure 4. Relay device installed on an electric power pole at site 11 (see red circle). Measurements were performed along the edge of the street on both sides of the power pole.

Figure 5. Location of an access point (AP) installed on an electric power pole at site 12 (see red circle). Measurements were performed along the edge of the street in one direction from the power pole.

Instrumentation Used in Measurements

The primary focus of this study was the magnitude of RF fields emitted by the Hawaiian Electric Company smart meters. Due to the highly intermittent nature of the smart meter transmitters, a spectrum analyzer based detector was used for the measurements (Narda Selective Radiation Meter model SRM-3006, SN D-0069). Figure 6 shows the instrument which consists of a wideband probe/antenna (SN K-0242) that is connected to a spectrum analyzer that is controlled with firmware that allows for measurement and display of detected RF fields. A powerful feature of the SRM-3006 is that all measurements can be displayed directly as a percentage of the FCC MPE for general public exposure, automatically adjusting the measured field for the frequency dependency of the FCC MPEs.

A feature of the SRM-3006 that made it particularly useful in this investigation was a “scope mode” in which the instrument can be tuned to a specific frequency with an adjustable wide resolution bandwidth (RBW) so that detected signals can be measured in the time domain. This facilitated capture of bursts of RF signals emitted by the smart meters. For the measurements performed in scope mode, a RBW of 32 MHz was used when centered on a frequency of 915 MHz, the center of the license free band used by these smart meters. Use of the very wide RBW allows for detection of all signals emitted by the meter, regardless of where they may be in the 902-928 MHz band.

Figure 7 illustrates an example measurement of the smart meter signals displayed by the SRM-3006 during the study where the horizontal axis represents frequency and the vertical axis represents the measured magnitude of RF field expressed as a percent of the FCC MPE for public exposure. The peak RF field of each smart meter emission is captured across the band. Each peak represents one emission at one moment in time. Had a greater measurement time been used, more peaks on other frequencies would have been seen to fill out the overall band.

Figure 6. The Narda SRM-3006 Selective Radiation Meter is based on Fast Fourier Transform (FFT) spectrum analyzer technology and uses a probe/antenna to measure the absolute magnitude of incident RF fields across the frequency range of 26 MHz to 3,000 MHz and digitally converts the detected field to the equivalent percentage of the FCC MPE.

The SRM-3006, with accompanying probe/antenna, is capable of performing narrowband measurements of signals from 26 MHz to 3,000 MHz. For spectral measurements of the smart meter emissions, a RBW of 100 kHz was used (Note: the significantly wider RBW used for the time-domain measurements in scope mode was used to accommodate the fast rise time of the pulses as well as ensuring detection of emissions across the entire license free band). This value was deemed sufficient to allow accurate detection of the peak value of pulsed fields from the smart meter but was arrived at through evaluation of the indicated peak value of smart meter pulses with different RBWs. Calibration certificates for the SRM and probe/antenna are provided in Appendix A.

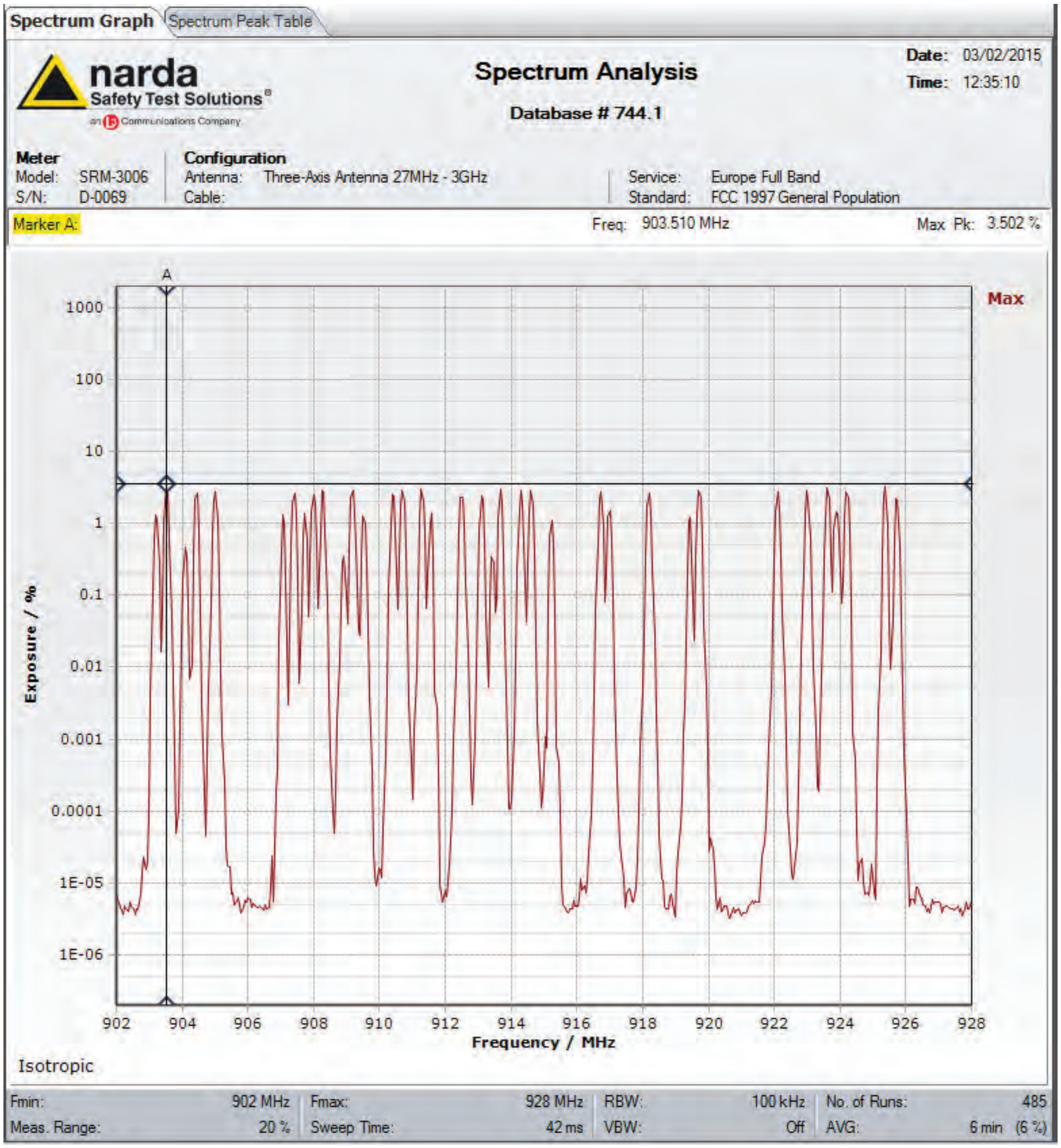

Figure 7. Example SRM-3006 spectrum measurement of the frequency hopping spread specturm signal produced by the Landis+Gyr smart meter at 1 ft from the meter. The use of markers allows for determining the peak value of field (in this case, 3.5% of the general public MPE).

Results

RF Field vs. Distance from Meters

Peak RF field measurements, taken at the various smart meter locations, expressed as a percent of the FCC MPE for general public exposure, are tabulated for a range of distances in Table 4. The greatest indicated value of field was obtained by using a marker feature on the SRM-3006 following capture of the bursting signal such that the maximum peak value was obtained. Each measurement was made with the SRM-3006 probe/antenna positioned in front of the meter at the specified distance with the instrument at the same height as the smart meter. Table 4 includes measurements at single meter installations (sites 1-6 and site 10) and at sites with a bank of meters (sites 7-9). Appendix B provides information about each measurement site.

Table 4. Summary of measured peak RF field values from the Landis+Gyr smart meters at various distances at all measurement sites except the relay, access point and park sites. The RF field value is expressed as a percentage of the FCC MPE for public exposure. The location of each site is provided in Appendix B.

	Site									
Distance (ft)	1	2	3	4	5	6	7	8	9	10
1	0.739	3.77	1.639	1.793	2.203	3.069	1.59/3.35*	3.30*	3.83*	7.113
2		1.467	0.230	0.647	1.308					2.837
3	0.185	1.118	0.185	0.451	0.584		0.423			1.098
4		0.644	0.266		0.268					0.855
5	0.077	0.468	0.198	0.201	0.219					0.441
6		0.512			0.121					
7		0.344								
8		0.164								
9		0.228								
10	0.034	0.085	0.068	0.075			0.069			
15				0.060						
17	0.013									
20				0.040						

*All meters being pinged. Sites 7, 8 and 9 with meter banks.

Field measurements were made no closer to the smart meter than 1 ft (0. 3m). IEEE Standard C95.3-2002 [6] recommends a minimum measurement distance of 0.2 m to minimize nearfield coupling and field gradient effects when using common broadband field probes. Measurement data can be distorted when using an isotropic probe to measure steep spatial gradients close to a radiating antenna element of a smart meter. These gradients can lead to considerable variation of the indicated amplitude of the field being measured over the volume of space occupied by the measurement probe elements. Nearfield coupling, and associated erroneously high field readings, can be particularly troublesome when employing field probes in the reactive near field that are comparable to the size of the source antenna. The elements inside the SRM-3006 probe/antenna are approximately 0.1 m long. Based on the potential for significant probe nearfield coupling with the smart meter internal transmitting antenna, measured values with surface contact between the probe/antenna and a smart meter should be avoided and considered likely substantial over-estimates of the true field. It was deemed appropriate that the minimum distance at which fields would be measured with the SRM-3006 should be one foot. A distance of one foot is equivalent to approximately one wavelength at 915 MHz.

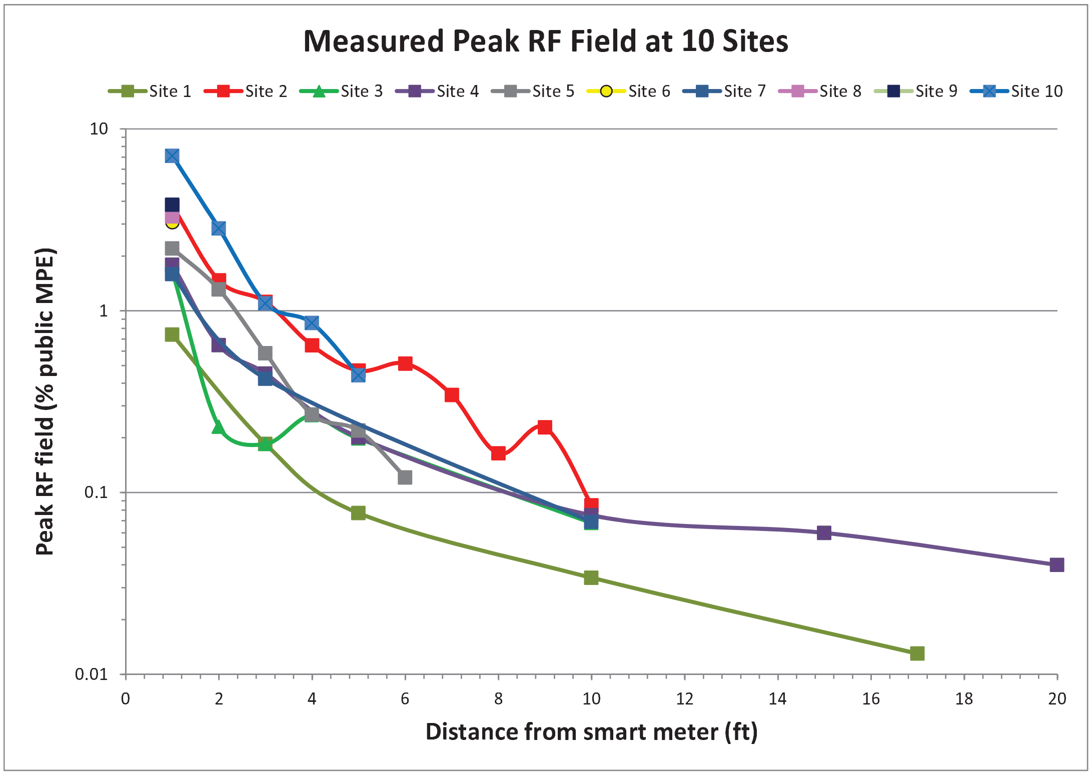

Figure 8. Measured peak RF field (percent of FCC public MPE) determined at 10 sites including single meters and meter banks (at sites 7, 8 and 9) in Honolulu and Pearl City, HI. These peak values of fields should be adjusted for duty cycle and spatial averaging for direct comparison to FCC limits for assessing compliance. The single greatest value observed from these measurements at one foot in front of a meter was 7.1% of the public MPE.

The data in Table 4 are graphically displayed in Figure 8. Variations in the measured value of fields are expected to be caused by measurement uncertainty and the real world presence of uneven ground over which the measurements were performed and that undoubtedly introduced reflections. Obstacles inhibited measurements at all distances at some of the locations and also could present the possibility of reflected fields that would interfere with the incident fields leading to apparent irregularities in the spatial variation of field with distance from a smart meter.

RF Field vs. Distance from Relay and Access Point

Ground level measurements of RF fields were performed at a relay and AP that are part of the Hawaiian Electric Company wireless network of smart meters. A relay is very similar to an endpoint smart meter but serves only for relaying data from various endpoint meters that have difficulty in directly communicating with an access point. The relay device operates in the 915 MHz band, the same as the endpoint meters with the same power level. An AP serves as a primary data collection device, receiving data from both endpoint meters and relays. The AP contains a 915 MHz band radio for communication with the endpoint meters and relays but, also, contains a cellular based radio for conveying the data received from the rest of the network back to Hawaiian Electric Company using a high speed data connection. Both relays and APs are typically installed on power poles at a height of at least 25 feet AGL.

Figure 9 illustrates the measured RF field values obtained at ground level near one of the relays in the Hawaiian Electric Company network (site 11). The measured values represent those found parallel to the street and either side of the power pole. Positive distances were in a southwesterly direction relative to the pole.

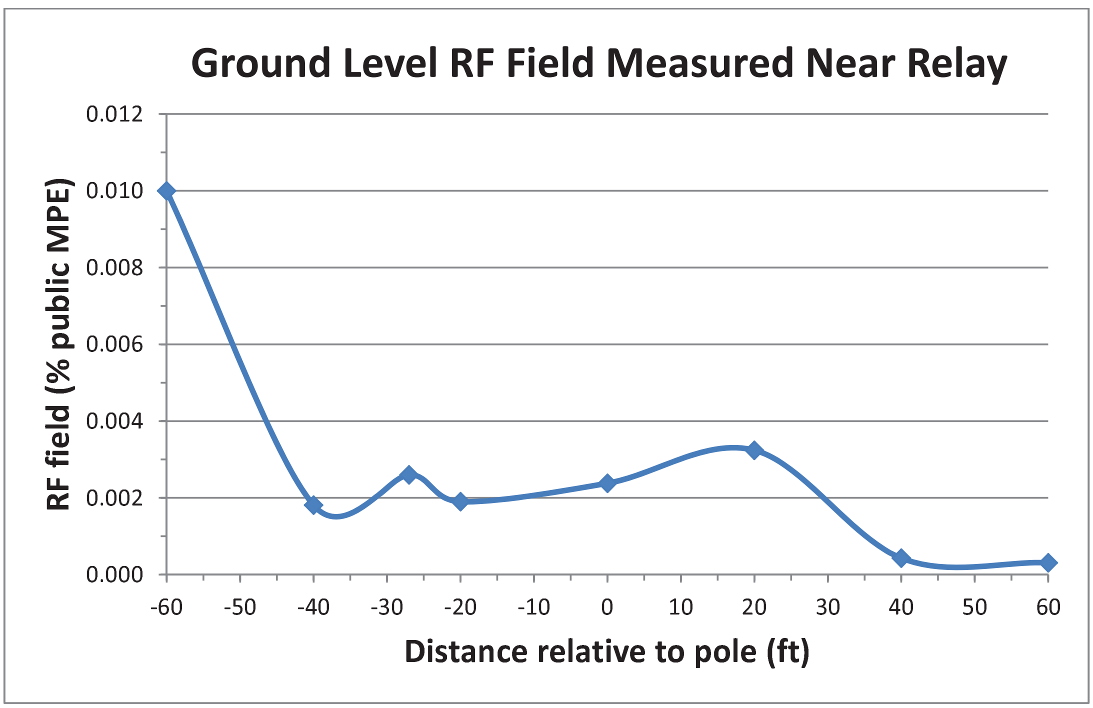

Figure 9. Measured ground level RF field near an Hawaiian Electric Company elevated relay.

The variation in measured values is a function of ground reflections and the pattern of the relay device in the elevation plane. The greatest value measured at the relay was equivalent to 0.010% of the FCC public MPE. The relatively low levels are related to the considerable height of the relay.

Similar measurements were performed at an AP (site 12) with a similar mounting height as the relay discussed above. Measurement points were on the sidewalk, parallel to the street. The maximum measured field at ground level near the AP was 0.00246% of the public MPE. The increasing distances shown in Figure 10 represented more southerly points relative to the power pole on which the AP was installed.

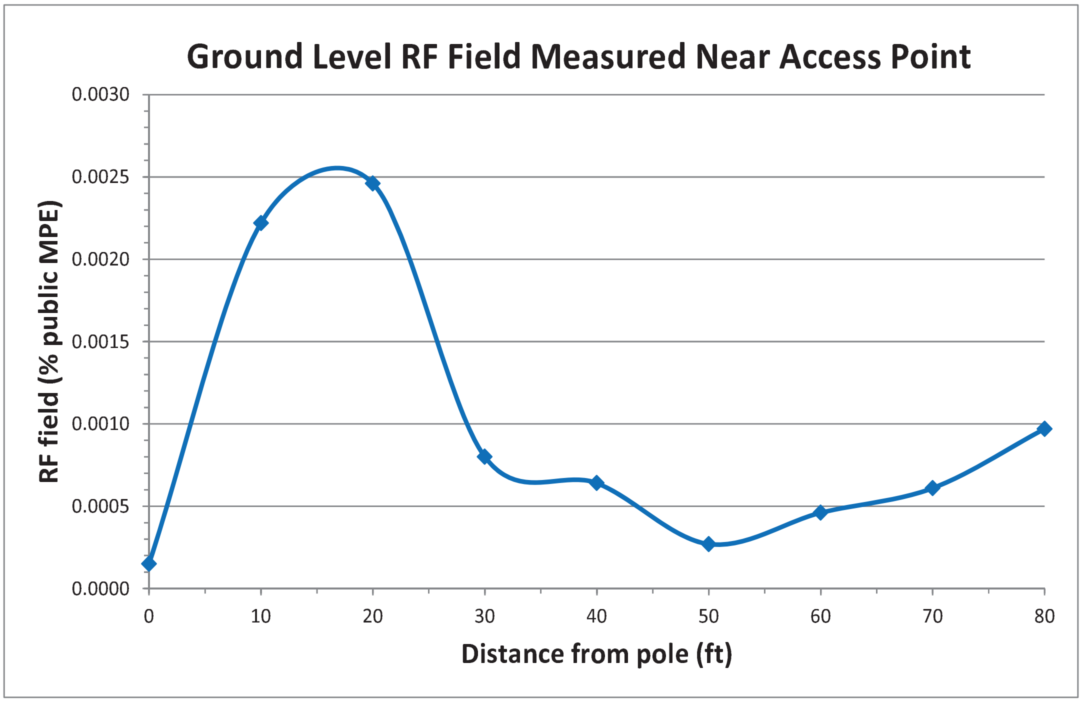

Figure 10. Measured ground level RF field near an Hawaiian Electric Company elevated access point.

RF Fields in Living Spaces

This study included measurements inside an apartment (site 8) and a condominium (site 7). Table 5 lists measured values of RF fields at different points within the apartment. On the inside surface of the wall directly behind the bank of smart meters, the field represented 0.00565% of the FCC public MPE. When compared to the maximum value found in front of the bank of meters at this site (3.3%), the interior value closest to the back side of the meter bank was approximately 600 times lower.

Table 5. Summary of RF field measurements in apartment at site 8. Fields expressed as a percent of the FCC public MPE.

Location	Description	Peak %MPE
1	Bedroom	0.00307
2	Patio	0.00083
3	Living room wall behind meters	0.00565
4	Kitchen	0.0460
5	Bath room	0.00130
6	Scan of entire apartment	0.0130

Table 6 summarizes measurements performed in the condominium at site 7. These data include a field measurement near the microwave oven when briefly operated to heat a cup of water. The microwave leakage from the oven was determined to be equivalent to 15.7% of the FCC MPE for the public determined at approximately 12 inches from the oven door.

Table 6. Summary of RF field measurements in condominium at site 7. Fields expressed as a percent of the FCC public MPE.

Location	Description	Peak %MPE
1	Bedroom wall closest to meter bank	0.00014
2	Balcony	0.00002
3	Living room	0.00002
4	Kitchen	0.00016
5	Bath room	0.00001
6	Meter closet adjacent to unit, all analog	0.00001
7	Meter bank adjacent to unit, no pinging @ 1 ft	1.9
8	Balcony (repeated measurement)	0.00012
9	Kitchen with microwave oven on	15.7
10	Scan of condominium in Wi-Fi band (maximum) oven off	0.00029

Time Domain Measurements of the Smart Meter Signal

When the Hawaiian Electric Company smart meters transmit data, the data are transmitted as a very brief digital message lasting several thousandths of a second (milliseconds, ms). Using the scope mode of operation of the SRM-3006, measurements were made of the duration of the smart meter transmission bursts (message length) on several occasions.

Figure 9 is a representative display of the measured time domain of four bursts of signals from the smart meter as it was pinged to respond. Using the marker feature of the SRM-3006, the duration of the bursts shown in Figure 9 were measured to be in the range of 2.59 to 11.7 ms. The different message lengths are related to the amount of data being transmitted at a given moment. Different signal levels are presumably related to the difference in field strength associated with the subject smart meter and the ping signal produced by the nearby FSU. Figure 9 should not be used to characterize the whole range of burst widths that may occur from the meter but, rather, to illustrate that the meter issues brief pulses of RF energy from time-to-time.

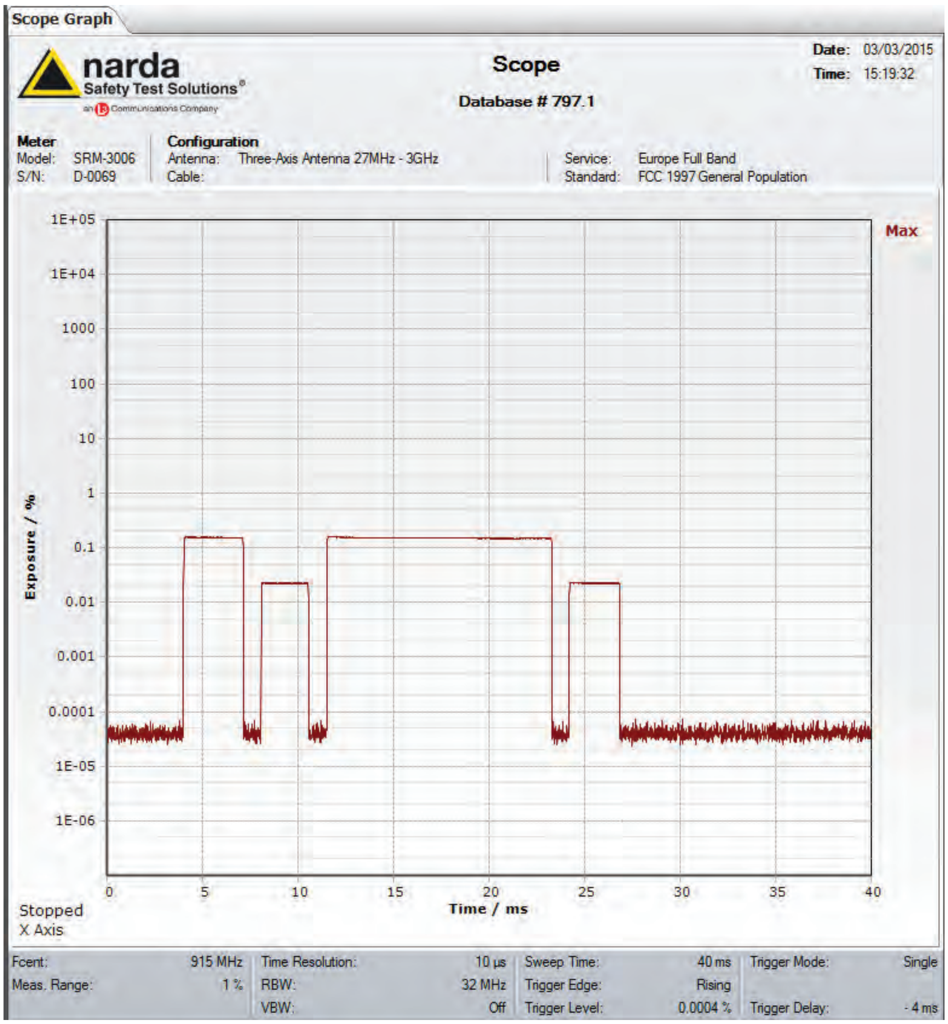

Figure 9. Time domain measurement of the signal bursts from a randomly selected smart meter. This image represents four successive bursts observed during the measurement. The digital message lengths ranged from 2.59 to 11.7 ms.

Estimates of Smart Meter Duty Cycles

RF exposure associated with the operation of the Hawaiian Electric Company wireless smart meters consists of highly intermittent RF fields. Although the peak value of the power density near these meters is much smaller than the MPE for public exposure adopted by the FCC, the time-averaged value of field is even less. From the perspective of a comprehensive assessment of compliance with the FCC rules on human exposure, the RF field is to be expressed in terms of an average value, averaged over any 30-minute window of time and spatially averaged over the dimensions of the body. With knowledge of the smart meter duty cycle, the peak values of RF fields can be adjusted to yield time-averaged values for comparison with the FCC MPEs. The time-averaged value of the RF emission from the smart meter is the product of the emission peak power density multiplied by the duty cycle and, then, expressed as a percentage of the FCC MPE. This maximum time-averaged value is then adjusted for spatial averaging for comparison with the FCC exposure limits.

In practice, a direct measurement of the 30-minute time-averaged value of smart meter emissions represents several significant challenges. First, simply acquiring the necessary field amplitude data over a 30-minute period places time constraints on the process, making it extremely time consuming to characterize exposures over a wide range of environments and varying proximity relative to the smart meter. Secondly, because the network activity of any given endpoint meter can vary from moment-to-moment and day-to-day, depending on network conditions and reporting times for the meters to transmit energy consumption data, any direct RF field measurement that might successfully yield the duty cycle will be subject to the normal but potentially erratic activity of meter transmissions over time. This imposes an uncertainty on how well a measurement of average exposure represents actual exposure at other times. Although measurement data acquired at a few meters limits the ability to quantify uncertainty in the measurement results, examining the time domain characteristics of emitted RF fields at deployed meters can provide useful insight to the actual duty cycle observed during the measurement period. This approach was used at ten of the measurement sites during this study including both single meter installations and banks of multiple meters.

Duty cycle measurements were performed by placing the SRM-3006 instrument near the subject smart meter(s) and acquiring, typically, a 30-minute duration time domain measurement of signal peak and average levels[7]. In each case, the meter, or meters, were pinged with the FSU to cause the greatest possible amount of transmitter activity. In addition, the measurements were, in most cases, performed to cover the time intervals during which meters report their readings back to Hawaiian Electric

[7] The SRM-3006 was configured to use only one of the three antenna axes that are normally used during RF field measurements. This allowed for the fastest response to the brief pulses emitted by the meter.

Company . This approach was deemed to result in the greatest opportunity to measure the greatest duty cycle of the meters, the relay or the AP.

The SRM-3006 provides for a direct measurement of duty cycle over user specified time intervals. Measurements included 5, 8.3, 20 and, mostly, 30-minute durations. An illustration of a duty cycle measurement with the SRM-3006 is shown in Figure 10 for site 10. This particular meter was selected specifically for the measurements because of its location within the mesh network to which it was assigned; because of its hierarchy within the network, this meter would be expected to exhibit transmit activity related to a relatively large number of meters that may communicate through it, depending on whether those meters are able to communicate directly to the AP. Based on examination of the Hawaiian Electric Company pilot smart meter service territory, this meter represented the best opportunity for finding maximum transmit activity and, hence, was deemed to provide a conservative measure of maximum meter activity across the network. During the measurement period of 30 minutes, a duty cycle of 0.00756 (0.756%) was determined. Figure 10 can be thought of as a representation of the meter transmit activity over the observation period of 30 minutes. The sweep time of the instrument is divided into as many as 4000 time-resolution increments depending on the overall sweep time. The instrument measures the overall peak and average value of all pulses occurring within each time increment and represents this result as a vertical bar. Each bar can, visually, only represent signal values associated with each time resolution increment. Hence although the peak and average signal amplitudes are accurately measured for all pulses, the number of pulses that occurred or precisely when they occur can be obscured by the particular time, and screen resolution of the instrument. For example, visually, the graphical presentation, as illustrated in Figure 10, can appear to occupy much more time than actually occurs, simply due to the degraded screen resolution.

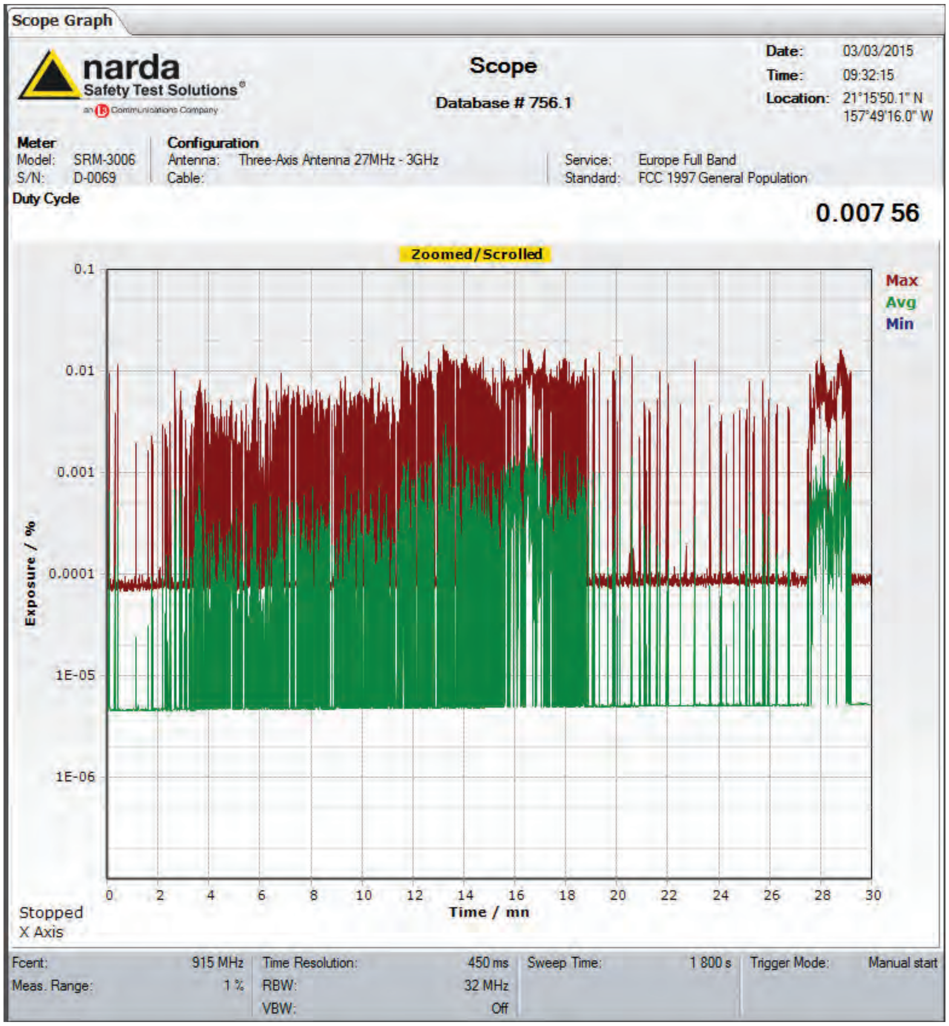

Figure 10. Illustration of duty cycle measurement at site 10 where a 30-minute duty cycle value of 0.00756 was determined (equivalent to 0.756%).

Duty cycle data were obtained at 10 sites in the Hawaiian Electric Company smart meter pilot service area as listed in Table 7. Repeated duty cycle measurements were performed at sites 6 (a single family home) and 8 (an apartment complex). The two measurements performed at site 8, the same apartment complex, were at two different meter banks, one consisting of 27 meters and the other, 34 meters. The duty cycle measurements at site 6, at the same single meter installation, were made over 20 minutes and 30 minutes.

Table 7. Summary of duty cycle measurement data at 10 sites in the Hawaiian Electric Company smart meter pilot service area.

	Site	No. Meters	Duration (min)	Duty cycle
Pukoloa Street, Honolulu, HI Single Meter	10	1	30	0.00038
Kamehameha Hwy., Pearl City, HI	9	19	5	0.00133
3rd Street, Pearl City, HI (Meter bank A)	8	27	30	0.00096
3rd Street, Pearl City, HI (Meter bank B)	8	34	5	0.00203
Pole mounted meter, Kalakaua Avenue, Honolulu, HI	13	1	30	0.00756
Relay on pole, 22nd avenue, Honolulu, HI	11	Relay	5	0.02452
AP overhead on power poles, Waimano Home Rd., Pearl City	12	AP	30	0.00408
Home,3rd Street, Pearl City, HI	6	1	30	0.00809
Home, 3rd Street, Pearl City, HI	6	1	20	0.00501
Home, Hunalewa Street, Honolulu, HI	4	1	5	0.00276
Home, Huanui Street, Honolulu, HI	3	1	30	0.00041
School, Diamond Head Road, Honolulu,	2	1	8.33	0.02985

The measured duty cycle values ranged from a minimum of 0.00038 (0.038%) to a maximum of 0.02985 (2.985%), this greatest duty cycle measured over 8.33 minutes. When measured over a full 30-minute period, the range of duty cycle values was from 0.00038 (0.038%) to a maximum of 0.00809 (0.809%) (124 times less than the peak value). During each of these measurements, the relevant meters were pinged with the FSU as continuously as possible to achieve the greatest duty cycle.

Spatially Averaged RF Fields

The RF exposure limits set by all of the present standards, guidelines or regulations (including those of the FCC) are expressed in terms of RF fields that are spatially averaged over the body dimensions. Because RF fields will be concentrated at the height of the meter, commonly encountered exposure will be highly non-uniform over the body. To explore how the RF fields from the Hawaiian Electric Company smart meters are distributed along a vertical axis, near one of the meters, at site 6, measurements were performed by using the SRM-3006 to capture the emissions of the smart meter at different heights AGL. Acquisition of the spatial variation of fields was accomplished by positioning the SRM-3006 to the side of the smart meter (mounted at 68.5 inches above ground to the center of the display screen on the meter) with the probe/antenna approximately 12 inches in front of the meter at seven different heights above ground. The data are presented in terms of the measured RF field (percentage of the MPE) vs. height AGL in Figure 11. At this particular meter, chosen because of convenience of access, the spatial maximum measured at the exact height of the meter was 3.07% of the MPE. The spatially averaged RF field corresponded to 23.2% of the spatial maximum value. For this meter mounting height, the spatially averaged RF field is roughly one-fourth of the maximum field at the same distance from the meter.

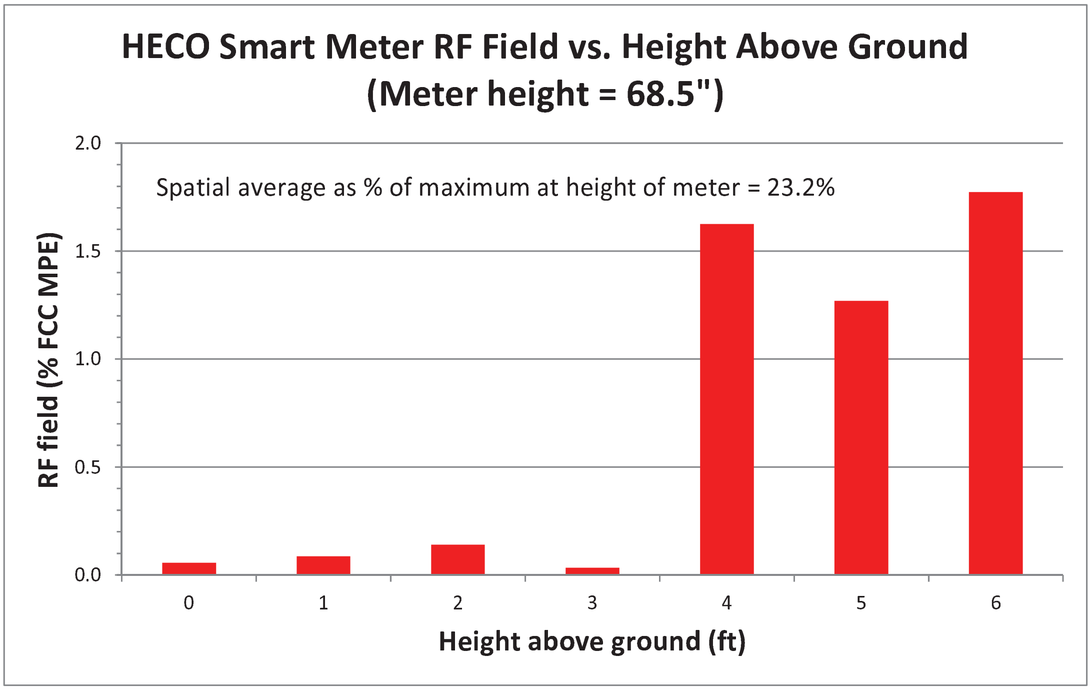

Figure 11. Measured RF fields along a vertical line from ground surface to a height of 6 feet (72 inches) (1.83 m) at approximately 1 ft in front of the Hawaiian Electric Company smart meter at site 6. The maximum field observed at the mounting height of the meter (68.5 inches, 5.7 feet) corresponded to 3.07% of the MPE. The overall spatial average is 23.2% of the spatial maximum value of field. A total of seven measurements, taken at different heights, limits the precision of the spatially averaged value of field.

Figure 11 illustrates how the RF field varies with height in the near vicinity of the meter. This variation is a function of reflections in the local region of the measurement probe but, most likely, is caused by the transmitting pattern of the smart meter in the elevation plane. This finding supports the measurement approach of positioning the measurement probe at the height of the meter to detect the greatest value of RF field.

Discussion

Measurement data presented in this report provide insight to characterizing potential exposure of individuals to the RF fields that can be produced by the wireless smart meters deployed by Hawaiian Electric Company in their pilot smart meter program. When taken collectively, the RF field data presented in this report show that common exposures of the public and Hawaiian Electric Company employees to the Hawaiian Electric Company smart meters investigated comply by a wide margin with the applicable human exposure rules of the FCC. This conclusion holds whether RF fields are quantified in terms of their instantaneous peak magnitude, their time-averaged value and/or their spatially averaged value. For example, at a distance of 1 foot directly in front of a smart meter, the greatest peak RF field measured in this study was 7.1% of the FCC public MPE found at a single meter. If this peak field value is adjusted for time-averaging by applying the largest measured 30-minute duty cycle (0.809%) and for spatial averaging (23.2% of spatial peak), the resulting exposure value for comparison with the FCC limit would be 0.0133% of the public MPE (a factor of 7,519 less than the MPE). Because only the greatest values of fields and duty cycles have been used in this evaluation, this should be deemed a conservative estimate of the average exposure that an individual might experience if standing very close to and in front of one of the Hawaiian Electric Company smart meters. In reality, typical maximum exposures would likely be at least an order of magnitude less in value. If this maximum estimate of potential exposure is compared to the threshold value associated with adverse biological effects (the MPE for the public is set with a safety factor of 50 times less than the adverse effect threshold), then the potential exposure value is some 376,000 times lower.

The FCC MPEs for public exposure are based on 30-minute time averages. Daily variability in the transmitter activity of most smart meters could result in 30-minute duty cycles being greater or less than that found in this study. However, the maximum duty cycle determined in a study of similar smart meters, based on transmitted messages from some 88,000 meters in the northern California area was 4.53% with 99.9% of the meters exhibiting duty cycles less than 1.12% [2]. Applying the maximum observed duty cycle from [2], the maximum potential exposure associated with the Hawaiian Electric Company smart meters sampled in this study would be about 0.0746% of the MPE.

RF field data reported here were measured at a minimum distance of 1 ft (0.3 m) from the face of various smart meters. This distance was used to eliminate possible nearfield coupling between the measurement probe/antenna and the smart meter that can lead to erroneously high indicated values. Nonetheless, RF field magnitudes at the minimum measurement distance can be projected to even shorter distances. The absolute maximum measured peak RF field, as a percentage of the FCC MPE, found in this study of 7.1%, could be expected to be as great as 16.0% of the MPE at 0.2 m (assuming free space propagation and not considering possible nearfield gain reduction of the antenna or taking spatial averaging into account). The FCC prescribes a 0.2 m (20 cm) distance as the distance at which all devices not intended for use at the surface of the body should comply with the MPEs. Hence, even at the 0.2 m distance, the data acquired in this project would imply that exposures would comply by a wide margin with the FCC MPE. A maximum value of time-averaged RF field equivalent to about 0.129% of the public MPE would be projected at 0.2 m using the maximum duty cycle measured in this study before applying an adjustment for spatial averaging.

It is noted that for those devices that are intended for operation at the surface of the body, more meaningful measures of exposure are in terms of specific absorption rate (SAR). For example, cellular telephones of the same maximum power as the 900 MHz radios within the smart meters evaluated here are subject to an FCC SAR limit of 1.6 W/kg in any one gram of tissue. Clearly, however, smart meters are not intended for use at the surface of the body.

The data also show that the Hawaiian Electric Company smart meter deployment results in only very weak RF fields inside residences. When the directional properties of the smart meter are considered with the RF field attenuating effect of common construction materials, peak RF fields corresponding to potential indoor smart meter exposures of substantially less than 1% of the MPE would be expected. For example, the greatest peak value of field found inside any residence, including an apartment next to a bank of smart meters, was 0.013% of the MPE.

The matter of multiple smart meters that are grouped together in banks, such as commonly found on apartment and condominium buildings, and how such groups of meters may affect potential exposure, was investigated at the apartment location. The measurement results indicate that the peak levels of RF fields were not reliably different from that found at a single smart meter in the bank of meters. This observation is consistent with the manner in which the smart meters in the Hawaiian Electric Company system operate and how the meters were pinged to produce a response. Smart meters as a whole transmit their intermittent and brief signals in different time slots. This means that there is a smaller likelihood that the instantaneous RF field will be represented by the superposition of signals arriving from a multiplicity of meters. Also, for the measurements conducted in this study, while there could be the possibility that more than one meter in the group might coincidentally be pinged at the exact same time to facilitate measurements, this was probably unlikely. Hence, it would seem that the peak RF field associated with multiple meters in a group is not likely to exceed the greatest peak value produced by any one of the meters. The time-averaged value of field in the near vicinity of a group of meters, however, would be expected to increase due to the greater, overall transmitter activity represented by the group as a whole. This potential increase in average field, however, must be weighed against the very low duty cycle of most meters. For instance, if all meters were assumed to operate with the observed maximum measured duty cycle (0.809%), the 30-min time-averaged RF field for the meter with the highest observed peak field in this study of 7.1% would be just 0.0574% of the public MPE (with no adjustment for spatial averaging). Hence, it would, presumably, require the simultaneous operation of some 1,742 meters to reach the FCC MPE value, a highly unlikely scenario within the Hawaiian Electric Company system. Further, this worst case analysis presumes that the maximum field measured for one meter, at one foot from the meter, would apply to all 1,742 meters and this is, basically, not physically possible since all meters would have to be arranged such that the distance between each meter and the exposure location one foot away was the same.

RF Emissions of Smart Meters Deployed by Hawaiian Electric Company

Smart meter RF emissions represent but one source of potential public exposure but because of the low power at which smart meter transmitters operate, the ambient RF fields are relatively weak. Other example sources of RF exposure include radio and television broadcasting, microwave ovens and wireless routers used in homes for distributing Internet connectivity. Often, these sources have the potential for producing RF fields that exceed those most commonly experienced from smart meters. An example includes the leakage of microwave energy from microwave ovens. At site 7, the leakage from a microwave oven was measured as great as 15.7% of the public MPE during its operation. Because of the essentially 100% duty cycle of microwave ovens, this value represents the full-time exposure at the measurement location. Microwave ovens generally represent the greatest source of RF fields in a home, albeit the fields are intermittent due to the use factor of the oven.

The use of wirelessly connected devices, such as laptop computers, is associated with RF emissions from the portable device as well as an AP or router that the device works through. RF fields in the range of 0.07% of the public MPE have been measured at a distance of one meter from routers and laptop computers [7].

RF fields from broadcasting stations are present in most locations around the world. A recent study found the maximum time time-averaged value of fields across the VHF-FM-UHF-cellular bands to be as much as 0.12% of the public MPE [8]. The contribution of AM radio broadcasting to this aggregate value of exposure was negligible.

In summary, RF fields exist throughout the environment and are produced by a multitude of different sources. The contribution of smart meters to overall potential exposure is typically small but will vary, depending on location and proximity to other RF sources.

Conclusions

Field measurements performed during March 2-4, 2015, were used to characterize potential RF exposure that might be experienced by individuals in close proximity to smart electric meters being deployed by Hawaiian Electric Company . The study shows that the smart meter fields are substantially less than applicable FCC limits for human exposure. Importantly, this finding of compliance with the FCC MPEs holds true whether or not the peak measured fields are adjusted for meter duty cycles (transmitter activity), whether spatial averaging or other factors that reduce RF fields such as the construction materials of homes are considered or whether the meters exist in a large group or whether individuals are outside near the smart meter or inside their residence. The strongest measured fields were, as expected, at the closest distance at which measurements were performed, i.e., 1 foot or 0.3 meters with the greatest peak field of 7.1% of the MPE. When adjusted for spatial averaging due to the highly non-uniform distribution of fields over the body dimensions, as well as 30-min time-averaging, the greatest potential exposure was concluded to be, at most, less than 0.0133% of the FCC MPE for public exposure. If the maximum duty cycle of smart meter emissions is assumed to reach the value found in an earlier study of similar meters which included some 88,000 meters, the maximum potential exposure would be comparable to 0.0746% of the public MPE.

Exposure of individuals in their smart meter equipped homes is commonly orders of magnitude less than that which would occur for an individual standing immediately adjacent to and in front of the meter. In measurements performed inside two residences, the greatest peak RF field found that was associated with smart meter operation was 0.013% of the MPE. This finding is related to the directional properties of the smart meter antenna and the shielding properties of the metal meter box and any building materials between the smart meter and the area behind the meter. Measured RF fields within areas immediately behind the meters were nominally about 1/600th of the value in front of the meter.

Large groups of smart meters, such as found on some apartment buildings, do not result in greater <u>peak</u> values of RF fields than those produced by an individual meter but can exhibit higher <u>average</u> field magnitudes due to the operation of multiple meter transmitters. Such higher average composite duty cycles do not, however, change the conclusion that such exposures are compliant with the established FCC limits since the duty cycles of individual meters are so small.

Ground level RF fields associated with the operation of relays and APs do not approach the FCC exposure limits. The significant mounting heights of relays and APs result in substantial reductions of field magnitude with the greatest peak field on the ground near a relay investigated being 0.010% of the MPE.

The RF fields produced by Hawaiian Electric Company smart meters are constrained by the low power of the transmitter and low antenna gain (low EIRP). A one-watt transmitter limits the maximum emitted RF field that can exist near a smart meter. When the results of this assessment are viewed from the perspective that the FCC MPE includes a safety factor of 50 against adverse health effects, the potential exposure of persons near the Hawaiian Electric Company smart meters not only complies by a wide margin with the exposure limit itself but will be at least 376,000 times less than that value associated with adverse health effects.

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Appendix A
Calibration Certification of the Narda SRM-3006 Selective Radiation Meter

Page 1 of 1

L3 communications
Narda Microwave East

Certificate of Calibration

L-3 Communications, Narda Microwave-East, hereby certifies that the referenced instrument has been calibrated by qualified personnel to Narda's approved test procedures.

Furthermore, the instrument meets, or exceeds, all published specifications and the calibration has been performed with test instrumentation that, where applicable, is traceable to the National Institute of Standards and Technology.

Narda's calibration measurements are traceable to the National Institute of Standards and Technology to the extent allowed by the bureau's calibration facilities.

Customer: RICHARD TELL ASSOCIATES
COLVILLE, WA 99114-9352

Certificate #: 128352 1

Model #: 3006/123/USA

Serial #: D-0069

Description: SRM 3006 W/6 GHZ ANTENNA

PO #: AMEX XXXX 1000

Date Calibrated: 02/25/2013

R.O. #: 128352

Hugh Saunders
Hugh Saunders
Test

Ken Peck
Quality Assurance

L-3 COMMUNICATIONS, NARDA MICROWAVE-EAST, 435 MORELAND ROAD, HAUPPAUGE, NEW YORK 11788, TEL: 631-231-1700, FAX: 631-231-1711

Narda Safety Test Solutions GmbH
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Phone: +49 7121 9732 0 - Fax: +49 7121 9732 790

narda
Safety Test Solutions®
an L3 Communications Company

Calibration Certificate

Narda Safety Test Solutions hereby certifies that the object referred to in this certificate has been calibrated by qualified personnel using Narda's approved procedures. The calibration was carried out in accordance with a certified quality management system which conforms to ISO 9001

OBJECT	Antenna, Three-Axis, E-Field, 27 MHz to 3 GHz
MANUFACTURER	Narda Safety Test Solutions GmbH
PART NUMBER (P/N)	3501/03
SERIAL NUMBER (S/N)	K-0242
CUSTOMER	
CALIBRATION DATE	20-Feb-2013
RESULT ASSESSMENT	within specifications
AMBIENT CONDITIONS	Temperature: (23 ± 3) °C Relative humidity: (20 to 60) %
CALIBRATION PROCEDURE	3000-8702-00A

ISSUE DATE: 2013-02-20

MANAGEMENT SYSTEM

CALIBRATED BY
Kretschmann

AUTHORIZED SIGNATORY

Certified by DQS against ISO 9001:2008 (Reg.-No. 099379 QM08)

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CALIBRATION PROCEDURE

The calibration of RF field strength probes involves the generation of a calculable linearly polarized electromagnetic field, approximating to a plane wave, into which the device is placed.
The RSS value of three axis is used.

At each test frequency, the probe is orientated in the analytic angle (54.74 degrees between probe axis and electric field vector) and rotated 360 degrees. The noted indicated output voltage is calculated from the geometric mean of the minimum and maximum readings during rotation. The antenna factor is calculated from the ratio of the applied field strength to the output voltage (nominal impedance 50 Ohm). The minimum and maximum readings during rotation are further used to calculate the ellipse ratio.
A power meter head is connected by means of an ferrite beaded 50 Ohm coaxial cable.

A Crawford TEM cell is used to generate the known field at frequencies up to 100 MHz. The field strength is derived from the TEM cell's properties and from the output power of the cell.
Over the frequency range from 200 MHz to 1.6 GHz, the probe is positioned in front of a double balanced ridge horn antenna. The field strength is set to a known value by means of a calibrated E-field reference probe.
Above 1.7GHz the probe is positioned with the boresight of a linearly polarized horn antenna. The field strength is derived from the mechanical dimensions and the input power of the antenna.

The antenna factor is permanently stored in the antenna connector memory. When combined with the SRM basic unit (BN 3001 series) the frequency response of the antenna is automatically compensated.

METROLOGICAL TRACEABILITY

The calibration results are traceable to National Standards, which are consistent with the recommendations of the General Conference on Weights and Measure (CGPM), or to standards derived from natural constants. Physical units, which are not included in the list of accredited measured quantities such as field strength or power density, are traced to the basic units via approved measurement and computational methods.
The equipment used for this calibration is traceable to the reference listed above and the traceability is guaranteed by ISO 9001 Narda internal procedure.

STANDARD	MANU-FACTURER	MODEL	SERIAL NUMBER	CERTIFICATE	NEXT CAL. DATE	TRACE
Power Sensor	R&S	NRV-Z4	100122	0277 D-K-15195-01-00 2012-04	2014-04	DAkkS
Millivoltmeter	R&S	URV55	100213	0253 D-K-15195-01-00 2012-08	2014-08	DAkkS
Setup "A" (1800 MHz to 3 GHz)						
Calliper	Preisser	0-800mm	310121016	1183737 DKD-K-12001 2011-03	#	DKD
Power Sensor	agilent	8481A	US37299951	1-3573582599-1	2013-09	UKAS147
Power Sensor	agilent	8481A	US37299952	1-3573640729-1	2013-09	UKAS147
Power Meter, T	agilent	E4419B	MY40330449	1-4868346583-1	2014-12	UKAS147
Setup "B" (200 MHz to 1600 MHz)						
E-Field Referer	Narda	Type 9.2	V-0017	51200637E	#	SIT08
Power Sensor	agilent	8481A	US37299870	1-3573582423-1	2013-09	UKAS147
Power Sensor	agilent	8481A	2702A57611	1-3573507236-1	2013-09	UKAS147
Power Meter, T	agilent	E4419B	GB43311917	1-3791659810-1	2013-12	UKAS147
Setup "D" (100 kHz to 100 MHz)						
Calliper	Preisser	0-800mm	310121016	1183737 DKD-K-12001 2011-03	#	DKD
Millivoltmeter	R&S	URV55	100627	0222 D-K-15195-01-00 2012-10	2014-10	DAkkS
Power Sensor	R&S	NRV-Z51	101777	0360 D-K-15195-01-00 2012-12	2014-12	DAkkS
Attenuator	Weinschel	49-30-33	KC115	220851 D-K-15012-01-00 2011-07	2014-07	DAkkS

\# Reference standard; not used for routine calibration

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UNCERTAINTY

The uncertainty stated in this document is the expanded uncertainty with a coverage factor of 2 (corresponding, in the case of normal distribution, to a confidence probability of 95%).

The uncertainty analysis for this calibration was done in accordance with the ISO-Guide (Guide to the expression of Uncertainty in Measurement). The uncertainties are derived from contributions from the measurement of power, impedance, attenuation, mismatch, length, frequency, stability of instrumentation, repeatability of handling and field uniformity in the field generators (TEM cell and anechoic chamber).

This statement of uncertainty applies to the measured values only and does not make any implementation or include any estimation as to the long-term stability of the calibrated device.

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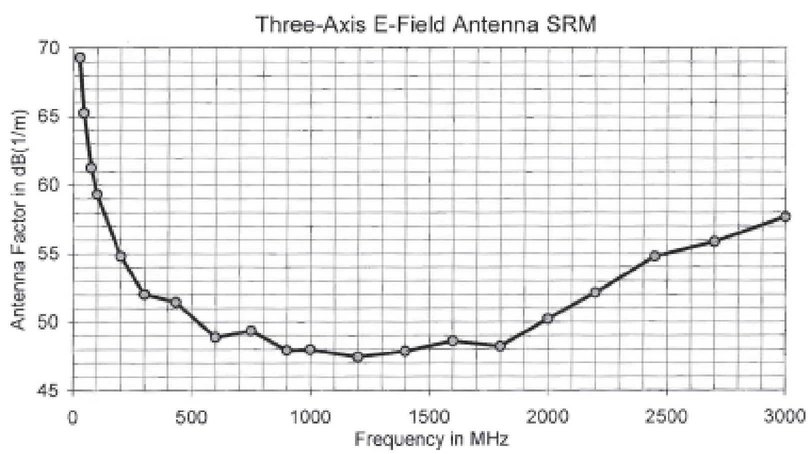
RESULTS

Frequency Response **passed**

Frequency in MHz	E_applied in V/m	Output voltage in dB(μV)	Uncertainty in dB	Antenna Factor in dB(1/m)	At receipt deviation in dB
26	10,0	70,70	1,0	69,30	-0,15
45	10,0	74,74	1,0	65,26	-0,02
75	10,0	78,73	1,0	61,27	-0,22
100	10,0	80,66	1,0	59,34	-0,34
200	10,0	85,21	1,0	54,79	0,04
300	10,0	87,98	1,0	52,02	0,06
433	10,0	88,57	1,5	51,43	0,20
600	10,0	91,12	1,5	48,88	0,46
750	10,0	90,65	1,5	49,35	0,30
900	10,0	92,10	1,5	47,90	-0,35
1000	10,0	92,04	1,5	47,96	-0,55
1200	10,0	92,57	1,5	47,43	0,37
1400	10,0	92,16	1,5	47,84	0,00
1600	10,0	91,41	1,5	48,59	-0,19
1800	10,0	91,80	1,0	48,20	0,31
2000	10,0	89,80	1,0	50,20	0,76
2200	10,0	87,88	1,0	52,12	0,51
2450	10,0	85,23	1,0	54,77	0,12
2700	10,0	84,17	1,0	55,83	0,06
3000	10,0	82,34	1,0	57,66	0,01

Frequency Flatness (100 - 3000 MHz): 11,9 dB

The antenna factors stored in the memory chip in the control cable are automatically applied by the Selective Radiation Meter (SRM) to allow the user to measure field strengths.



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Rotational Ellipticity **passed**

Frequency in MHz	Ellipse Ratio in dB
26	± 0,11
45	± 0,09
75	± 0,09
100	± 0,09
200	± 0,09
300	± 0,11
433	± 0,08
600	± 0,08
750	± 0,15
900	± 0,20
1000	± 0,19
1200	± 0,40
1400	± 0,40
1600	± 0,67
1800	± 0,62
2000	± 0,80
2200	± 1,25
2450	± 1,30
2700	± 1,31
3000	± 1,58

Output Return Loss **passed**

Appendix B
Measurement Site Locations/Descriptions

Measurement Sites Used During the Smart Meter Study

Site	Address	Description
1	Kilauea Ave., Honolulu	Single meter residence
2	Diamond Head Rd., Honolulu	Single meter commercial, school, duty cycle also measured
3	Huanui St., Honolulu	Single meter residence, duty cycle also measured
4	Hunalewa St., Honolulu	Single meter residence, duty cycle also measured
5	Harding Ave., Honolulu	Single meter residence
6	3rd St., Pearl City	Single meter residence, duty cycle also measured
7	Kilauea Ave., Honolulu	Condominium, near 6 meter bank, interior and exterior measurements
8	3rd St., Pearl City	Apartment, near 27 meter bank, interior and exterior measurements, duty cycle also measured on two meter banks
9	Kamehameha Hwy., Pearl City	19 meter bank (14 active meters) commercial, duty cycle also measured
10	Pukoloa St., Honolulu	Single meter commercial, auto dealership, duty cycle also measured
11	22nd Ave., Honolulu	Overhead relay, measurements at ground level; duty cycle also measured
12	Waimano Home Rd., Pearl City	Overhead access point, measurements at ground level; duty cycle also measured
13	Kalakaua Ave., Honolulu	Pole mounted single meter in park, used for duty cycle measurement

Glossary of Terms Used in this Report

AMI- Advanced metering infrastructure.

antenna- A device designed to efficiently convert conducted electrical energy into radiating electromagnetic waves in free space (or vice versa).

antenna pattern- Typically a graphical plot illustrating the directional nature of radiated fields produced by an antenna. The pattern also shows the directional nature of the antenna when used for receiving signals.

attenuation- The phenomenon by which the amplitude of an RF signal is reduced as it moves from one point in a system to another. It is often given in decibels.

averaging Time (T_{avg})- The appropriate time period over which exposure is averaged for purposes of determining compliance with the maximum permissible exposure (MPE). For exposure durations less than the averaging time, the maximum permissible exposure, MPE', in any time interval, is found from:

$$MPE' = MPE\left(\frac{T_{avg}}{T_{exp}}\right)$$

where T_{exp} is the exposure duration in that interval expressed in the same units as T_{avg}. T_{exp} is limited by restriction on peak power density.

azimuth pattern- Commonly a term referring to an antenna pattern showing the distribution of radiated field from the antenna in the azimuth plane (horizontal plane).

bandwidth- A measure of the frequency range occupied by an electromagnetic signal. It is equal to the difference between the upper frequency and the lower frequency, usually expressed in Hertz.

calibration correction factor- A numerical factor obtained through a calibration process that is used to multiply RF field meter readings by to obtain corrected readings to achieve the maximum accuracy possible.

continuous exposure- Exposure for durations exceeding the corresponding averaging time (usually 6 minutes for occupational exposure and 30 minutes for the general public). Exposure for less than the averaging time is called short-term exposure.

dBi- decibel referenced to an isotropic antenna- a theoretical antenna which transmits (or receives) electromagnetic energy uniformly in all directions (i.e. there is no preferential direction).

dBm- A logarithmic expression for radiofrequency power where 0 dBm is defined as equal to 1 milliwatt (mW). Hence, +10 dBm is 10 mW, +20 dBm is 100 mW, etc., and -10 dBm is 0.1 mW.

decibel (dB)- A dimensionless quantity used to logarithmically compare some value to a reference level. For power levels (watts or watts/m^2), it would be ten times the logarithm (to the base ten) of the given power level divided by a reference power level. For quantities like volts or volts per meter, a decibel is twenty times the logarithm (to the base ten) of the ratio of a level to a reference level.

duty cycle- A measurement of the percentage or fraction of time that an RF device is in operation. A duty cycle of 1.0, or 100%, corresponds to continuous operation. Also called duty factor. A duty cycle of 0.01 or 1% corresponds to a transmitter operating on average only 1% of the time.

effective isotropic radiated power (EIRP)- The apparent transmitted power from an isotropic antenna (i.e. a theoretical antenna that transmits uniformly in all possible directions as an expanding sphere).

electric field strength- A field vector (E) describing the force that electrical charges have on other electrical charges, often related to voltage differences, measured in volts per meter (V/m).

electromagnetic field- A composition of both an electric field and a magnetic field that are related in a fixed way that can convey electromagnetic energy. Antennas produce electromagnetic fields when they are used to transmit signals.

electromagnetic spectrum- The range of frequencies associated with electromagnetic fields. The spectrum ranges from extremely low frequencies beginning at zero hertz to the highest frequencies corresponding to cosmic radiation from space.

elevation pattern- Commonly a term referring to an antenna pattern showing the distribution of radiated field from the antenna in the elevation plane (vertical plane).

endpoint meter- A term used to designate a smart meter that is installed on a home or business to record and transmit electric energy consumption but that does not provide access point features.

exposure- Exposure occurs whenever a person is subjected to electric, magnetic or electromagnetic fields or to contact currents other than those originating from physiological processes in the body and other natural phenomena.

far field- The far field is a term used to denote the region far from an antenna compared to the wavelength corresponding to the frequency of operation. It is a distance from an antenna beyond which the transmitted power densities decrease inversely with the square of the distance.

Federal Communications Commission (FCC)- The Federal Communications Commission (FCC) is an independent agency of the US Federal Government and is directly responsible to Congress. The FCC was established by the Communications Act of 1934 and is charged with regulating interstate and international communications by radio, television, wire, satellite, and cable. The FCC also allocates bands of frequencies for non-government communications services (the NTIA allocates government frequencies). The guidelines for human exposure to radio frequency electromagnetic fields as set by the FCC are contained in the Office of Engineering and Technology (OET) Bulletin 65, Edition 97-01 (August 1997). Additional information is contained in OET Bulletin 65 Supplement A (radio and television broadcast stations), Supplement B (amateur radio stations), and Supplement C (mobile and portable devices).

FFT- Fast Fourier Transform, a mathematical method for transforming data acquired in the time domain into the frequency domain. Some modern spectrum analyzers use high speed analog to digital converters (ADCs) to sample an input signal in the time domain and electronically implement the FFT to calculate and display the frequency spectrum of the sampled signal(s).

frequency hopping – A term describing the transmission frequency of a spread spectrum transmitter or transceiver that jumps (hops) instantaneously to different frequencies within a certain band of frequencies.

gain, antenna- A measure of the ability of an antenna to concentrate the power delivered to it from a transmitter into a directional beam of energy. A search light exhibits a large gain since it can concentrate light energy into a very narrow beam while not radiating very much light in other directions. It is common for cellular antennas to exhibit gains of 10 dB or more in the elevation plane, i.e., concentrate the power delivered to the antenna from the transmitter by a factor of 10 times in the direction of the main beam giving rise to an effective radiated power greater than the actual transmitter output power. In other directions, for example, behind the antenna, the antenna will greatly decrease the emitted signals. Gain is often referenced to an isotropic antenna (given as dBi) where the isotropic antenna has unity gain (unity gain is equivalent to 0 dBi). At regions out of the main beam of an antenna, such as behind the antenna in a smart meter, the gain of the antenna may be so small that it is less than that of an isotropic antenna and has a gain specified as a negative dBi.

gigahertz (GHz)- One billion hertz.

ground reflection factor- A factor commonly used in calculations of RF field power densities that expresses the power reflection coefficient of the ground over which the RF field is being computed. The purpose of the factor is to account for the fact that ground reflected RF fields can add constructively in an enhanced (stronger) resultant RF field. The ground reflection factor becomes significantly less important for near-field exposures very close to an RF source, such as a smart meter.

hertz- The unit for expressing frequency, one Hertz (Hz) equals one cycle per second.

IEEE- Institute of Electrical and Electronics Engineers.

isotropic antenna- A theoretical antenna which transmits (or receives) electromagnetic energy uniformly in all directions (i.e. there is no preferential direction). The radiated wavefront is assumed to be an expanding sphere.

isotropic probe- Similar to isotropic antenna but normally related to RF measurement instruments designed to evaluate the magnitude of RF fields from a safety perspective. The isotopic character of the probe results in a measurement of the resultant RF field produced by all polarization components.

"license free"- A phrase meaning that an RF transmitter is operated at such low power and within an authorized frequency band that no formal license to operate is required by the FCC. There are restrictions placed on these devices, however, such as they shall not produce interference and/or may not create RF fields exceeding particular field strengths.

max hold spectrum- A feature often present on instruments such as spectrum analyzers in which the instantaneous peak values of measured signals are captured and continuously displayed so that, over time, the absolute maximum signal values can be determined even if they were only present for a short period.

maximum permissible exposure (MPE)- The rms and peak electric and magnetic field strength, their squares, or the plane wave equivalent power densities associated with these fields and the induced and contact currents to which a person may be exposed without harmful effect and with an acceptable safety factor.

megahertz (MHz)- One million hertz.

mesh network- A term describing a network, typically wireless, in which multiple nodes communicate among themselves and data can be relayed via various nodes to some access point. Mesh networks are self healing in that should a particular pathway become nonfunctional for some reason, alternative paths are automatically configured to carry the data. Mesh networks can expand beyond the normal range of any single node (smart meter) by relaying of data among the different meters.

microwatts- One-millionth of a watt, a microwatt (μW) or 10^{-6} watts.

modulation- Refers to the variation of either the frequency or amplitude of an electromagnetic field for purposes of conveying information such as voice, data or video programming.

near field- A region very near antennas in which the relationship between the electric and magnetic fields is complex and not fixed as in the far field, and in which the power density does not necessarily decrease inversely with the square of the distance. This region is sometimes defined as closer than about one-sixth of the wavelength. In the near field region the electric and magnetic fields can be determined, independently of each other, from the free-charge distribution and the free-current distribution respectively. The spatial variability of the near field can be large. The near field predominately contains reactive energy that enters space but returns to the antenna (this is different from energy that is radiated away from the antenna and propagates through space).

nearfield coupling- A phenomenon that can occur when an RF measurement probe is placed within the reactive near field of an RF source such that the probe interacts strongly with the source in a way that typically draws power from the source than would not occur at greater distances. When nearfield coupling occurs, field probe readings are typically erroneously greater than the actual RF field magnitude.

plane wave- Wave with parallel planar (flat) surfaces of constant phase (See also Spherical wave). Note: The cover of this report shows an idealized spherical wave that expands outward- in an appropriate region that this spherical wave can be considered as a plane (flat) wave.

polarization- The orientation of the electric field component of an electromagnetic field relative to the earth's surface. Vertical polarization refers to the condition in which the electric field component is vertical, or perpendicular, with respect to the ground, horizontal polarization refers to the condition in which the electric field component is parallel to the ground.

power density- Power density (S, sometimes called the Poynting vector) is the power per unit area normal to the direction of propagation, usually expressed in units of watts per square meter (W/m^2) or, for convenience, milliwatts per square centimeter (mw/cm^2) or microwatts per square centimeter ($\mu w/cm^2$). For plane waves, power density, electric field strength, E, and magnetic field strength, H. are related by the impedance of free space, i.e. 120π (377) ohms. In particular, $S = E^2/120\pi = 120\pi H^2$ (Where E and H are expressed in units of V/m and A/m, respectively, S is in units of

W/m$^{2)}$. Although many RF survey instruments indicate power density units, the actual quantities measured are E or E^2 or H or H^2.

radiation pattern- A description of the spatial distribution of RF energy emitted from an antenna sometimes referred to as transmitting pattern. Two radiation patterns are required to completely describe the transmitting performance of an antenna, one for the azimuth plane and another for the elevation plane.

radio- A term used loosely to describe a radio transmitter or transceiver.

radio frequency (RF)- Although the RF spectrum is formally defined in terms of frequency as extending from 0 to 3000 GHz, the frequency range of interest is 3 kHz to 300 GHz.

radio spectrum- The portion of the electromagnetic spectrum with wavelengths above the infrared region in which coherent waves can be generated and modulated to convey information- generally about 3 kHz to 300 GHz.

reflection- An electromagnetic wave (the "reflected" wave) caused by a change in the electrical properties of the environment in which an "incident" wave is propagating. This wave usually travels in a different direction than the incident wave. Generally, the larger and more abrupt the change in the electrical properties of the environment, the larger the reflected wave

resolution bandwidth- A specification for spectrum analyzers that denotes the ability of the analyzer to identify two signals on different frequencies, a measure of the frequency selectivity of the analyzer.

resultant field- The combined result of all polarization components of an electromagnetic field found by determining the sum of three orthogonal components of power density or the root sum squared of three orthogonal components of electric or magnetic field strength.

RF - Radiofrequency.

root-mean-square (RMS)- The effective value of, or the value associated with joule heating, of a periodic electromagnetic wave. The RMS value of a wave is obtained by taking the square root of the mean of the squared value of the wave.

shielding effectiveness- A measure of the ability of a material or structure to attenuate RF fields, typically specified in decibels.

spatial average- For RF exposure limits, a determination of the average value of power density over the projected cross section area of the body. In practice, an average along a vertical line representing the height of a person.

specific absorption rate (SAR)- The time derivative of the incremental energy absorbed by (dissipated in) an incremental mass contained in a volume) of a given density. SAR is expressed in units of watts per kilogram (W/kg) or milliwatts per gram (mW/g). Guidelines for human exposure to radio frequency fields are based on SAR thresholds where adverse biological effects may occur. When the human body is exposed to a radio frequency field, the SAR experienced is proportional to the squared value of the electric field strength induced in the body.

spectrum analyzer- An electronic instrument, similar to a receiver, that sweeps across a part of the RF spectrum and displays detected signals as peaks on a visual display screen. Spectrum analyzers normally continuously sweep repetitively over a given frequency band at a relatively high rate thereby allowing for the observation of intermittent signals.

spread spectrum- Refers to a method by which an RF signal that is generated in a particular bandwidth is deliberately spread in the frequency domain resulting in a signal with a wider bandwidth. Such a technique is used to enhance secure communications, to reduce interference and to prevent detection.

time-averaged exposure- In the context of RF exposure limits, an average of the exposure value over a specified time period. Commonly, for occupational exposures, the averaging time is six-minutes and for members of the general public 30-minutes. All scientifically based RF exposure limits are in terms of time-averaged values.

transceiver- A radio device that has both transmitting and receiving capability. Strictly, the radio devices in Smart Meters are transceivers since they can both transmit data and receive data. Commonly, in the context of evaluating RF fields, the term transmitter or radio is used to refer to the transmitting feature of the transceiver.

Attachment 4

Smart Grid Foundation Project

Exhibit D

Safety and Health Manual – Chapter 16

Approved by: RCR	Hawaiian Electric Company Maui Electric Company Hawaii Electric Light Company	Safety & Health Manual
Date Revised: 12/3/12	Meter Service	Chapter: 16

Chapter Summary

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16.0 Objective

Hawaiian Electric Company, Hawaii Electric Light Company, and Maui Electric Company, will develop, maintain, and administer, these Meter Service safety requirements.

16.1 Purpose

This Chapter describes the safety policies and procedures necessary for employees, as well as contractors, who work in this challenging area, in order to provide a safe work environment. This written program addresses all applicable United States Occupational Safety & Health Administration (OSHA) laws and regulations set forth in 29 CFR 1910 (1910.269) and 29 CFR 1926, as well as all applicable rules and regulations.

16.2 Entering Customer Property

16.2.1 Employees shall always remain aware of their surroundings and look out for hazards (tripping or overhead), dogs, cats, or other animals.

16.2.2 Employees shall announce their presence if practical, and state their business when entering customer's premises.

16.2.3 Notify the customer when you leave, if practical.

16.3 Test Equipment and Fuses

16.3.1 Only approved test lamps, voltmeters, or voltage testers, shall be used for determining whether a circuit is energized or if a fuse is blown.

16.3.2 Fuse pullers or rubber gloves, shall be used in replacing cartridge fuses in energized service installations.

16.3.3 Refer to Chapter 5, section 5.5, for additional information on fuses.

Attachment 5

Smart Grid Foundation Project

Exhibit D

Cybersecurity and Privacy for Smart Grid Implementation

CYBERSECURITY AND PRIVACY FOR SMART GRID IMPLEMENTATION

The protection of business and customer information is a serious undertaking for the Hawaiian Electric Companies.[1] This is especially true with the advent of transforming into the modern utility of the future that utilizes "smart" technologies leveraging seamless connectivity and information greater than ever before. With this increase in network connectivity and use of information, there is also an increase in attempted cyber-attacks as cybercrime 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.

In order to protect against these new vulnerabilities and limit any further exposure of existing vulnerabilities, the Companies' Smart Grid Foundation Project ("SGF Project") will enhance and add new cybersecurity solutions that are designed to protect, monitor and manage such threats so that they are prevented and/or responded to with immediacy. This includes fortifying existing mitigations such as multi-level access controls, anti-virus software and a variety of intrusion sensors, while providing for additional security zones, more rigorous data management, and new security information and event management capabilities.

In this ever-changing environment, the Companies' completely concur with the Hawai'i Public Utilities Commission ("Commission") on the importance of a proactive privacy program emphasizing policies and practices that enable and demonstrate transparency and customer choice. The Companies' information and privacy program policies are based on evolving industry privacy standards and best practices, reviewed annually, and have been expanded to cover *all* customer data, to provide increased transparency and better customer understanding. The SGF Project furthers these goals, and allows for better bi-directional customer communication on data privacy.

As discussed below, this combination of incremental cybersecurity capabilities, coupled with a robust information and privacy policy framework that leverages informed customers via privacy notifications, will facilitate grid modernization in a safe and secured environment.

I. SMART GRID IMPLICATIONS FOR CYBERSECURITY

Smart Grid technologies will make the enterprise systems more complex, with new applications, network access points and data introduced into the grid. The SGF Project includes installation of Advanced Metering Infrastructure ("AMI") to support devices, such as smart meters, as well as additional computing systems that add new functionality to the grid. All of these changes will present potential vulnerabilities, both known and unknown.[2] With the

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[1] The "Hawaiian Electric Companies" or "Companies" are Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Maui Electric Company, Limited ("Maui Electric") and Hawaii Electric Light Company, Inc. ("Hawai'i Electric Light").

[2] 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).

implementation of multiple Smart Grid 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.

Smart Grid systems 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.[3] For instance, smart meters will now provide usage and operational data from the service location endpoint to both a centralized Meter Data Management System ("MDMS") for billing purposes as well as grid management systems used to provide for higher concentrations of renewable energy at the distribution level. As another example, Customer Facing Solutions ("CFS"), such as an online customer energy portal served through the web or a mobile device, will interface with the Companies' billing system, MDMS, outage management system and demand response applications, enabling customers to participate in grid management load shedding activities in real time using energy usage data information collected from their smart meters.

These systems will be a hybrid of sorts, combining capabilities and data exchanges to traditional business systems, as well as to traditional 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.

The low-power RF mesh network being installed as part of the SGF Project will greatly expand the attack surface of the Companies' integrated data networks. This expanded RF network will include more endpoints – by several orders of magnitude – than the traditional microwave data links the Companies have operated for many years. The addition of new Smart Grid 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.

II. VULNERABILITIES OF A SMART GRID

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

A. CRITICAL INFRASTRUCTURE

Smart Grid systems present new vulnerabilities that, if exploited, can have a significant impact on the operations of the electrical grid itself. 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-attacks. Thus, as further described below, several

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

risk mitigation activities are planned on top of what the Companies already have in place, including additional network segmentation, cryptographic systems and role-based access controls with stronger authentication.

B. DATA

The traditional risk for utilities in the area of 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.

Customer trust is important to the Companies and to the Smart Grid implementation, because a loss of trust would directly affect customer participation and the ability to fully realize the goals and benefits of the Smart Grid. The amount of customer data entrusted to utility companies has expanded rapidly and continues to do so. The most obvious example is smart meter data that can, if captured at short intervals and coupled with physical location knowledge, be analyzed to reveal details about specific customer behaviors. Newer types of customer data are also captured through non-traditional customer interactions such as social media, alternative billing and payment methods, and responses to a wider variety of voluntary programs in the areas of demand response.

III. SMART GRID CYBERSECURITY SAGEGUARDS

Smart Grid will require the Companies' cybersecurity protective measures and controls to be more comprehensive. Among the risk mitigations planned for the SGF 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 taken a proactive step to protect against cyber-attacks and unwarranted intrusions for their Smart Grid by implementing Silver Spring Networks' ("SSNI") Enhanced Security Package during the Companies Smart Grid Initial Phase demonstration project ("Initial Phase") on O'ahu, becoming one of the first utilities nationwide to utilize this additional level of security software. This industry leading security measure introduces more comprehensive data security processes and intrusion detection systems designed to specifically address the information conveyed over a grid's mesh network, such as that communicated between smart meters and utility back office systems. The Companies plan to continue to utilize this enhanced feature, along with additional layers of protection as they implement the SGF Project throughout their service territories.

The Companies' existing and planned security and privacy measures, coupled with the SSNI's advanced software solutions will result in a robust, comprehensive cybersecurity risk mitigation framework that will guide their Smart Grid implementation. This framework will create a unified approach in which the Companies can better prepare, prevent and recover from potential threats and ensure that customer and business information is kept protected.

A. CYBERSECURITY RISK MITIGATION FRAMEWORK

The National Institute of Standards and Technology's (NIST) *Framework for Improving Critical Infrastructure Cybersecurity*[4] describes five stages for its core risk mitigation functions: Identify, Protect, Detect, Respond, and Recover – each of which are 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"[5] strategy. In addition to incorporating protection mechanisms, the Companies need to expect 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 protection capability, and cost, performance and operational considerations.

1. Identify

The *Identify* core function is to develop 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 of an IT or OT infrastructure. A security risk assessment is a comprehensive study to discover and describe threats, vulnerabilities and risks, and to recommend system-specific risk mitigations. Several penetration tests and vulnerability assessments will be conducted by different third parties during the SGF Project as part of the system development life cycle release process.

2. Protect

The *Protect* core function is to develop and implement 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 smart meters and other remote devices, and endpoint protection for the required servers and workstations that will harvest the information transmitted over the Smart Grid's AMI network. Collectively, these will serve as additional layers of reinforcement against unwarranted intrusion during the SGF Project.

a. Network Segmentation

With the solutions added for Smart Grid, 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 Smart Grid 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.

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4 Available at http://www.nist.gov/cyberframework/.

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

The introduction of smart meters 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. Smart meter integration will require enhanced data network segmentation in order to better protect the network environments from compromise.

b. Encryption and Cryptographic Key Management Systems

Hawai'i law provides guidance for companies in the protection of customer data.[6] The Companies have implemented an encryption standard 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 Smart Grid 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 Smart Grid systems, particularly smart meters, the Companies will transition from managing a few thousand cryptographic keys to managing millions of cryptographic keys. Each of the approximately 450,000 smart 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.

c. Endpoint Protection (Servers and Workstations)

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

3. Detect

The *Detect* core function is to develop and implement the appropriate activities to identify the occurrence of a cyber-attack. These activities include a network intrusion detection system, a network and website scanning service, and a security incident event management system that will work together to constantly monitor and detect any threats or attacks that may arise.

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 monitored constantly, with staff callout as needed. The Companies also utilize a variety of commercially available systems to scan servers to detect 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-facing websites.

In addition, with the enhanced data network segmentation described above, there will be

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

more security zones from which to collect and correlate security events. This includes the additional firewalls to protect the perimeter of each zone, as well as the applications and other network appliances within the zones. Each of these devices creates an event log, and the log files need to be collected, aggregated, correlated and analyzed to detect any potential threats or attempted threats that may arise.

4. Respond

The *Respond* core function is to develop and implement 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 Smart Grid systems.

5. Recover

The *Recover* core function is to develop and implement 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 in preparation of potential attacks, as well as resistance, resilience and recovery after an attack. These capabilities will also be extended to Smart Grid systems.

Some of the risk mitigation activities described above, such as anti-virus software 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 better protect the more robust data and more complex grid infrastructure required by the Smart Grid.

B. PRIVACY

The Companies already have a robust privacy program, including policies and data governance, for protecting customer and business information. However, the advent of new technologies and customer choices as part of the ongoing transformation to a utility of the future requires constant monitoring and enhancement. While the cybersecurity risk mitigation activities described above protect personally identifiable information throughout the Companies' systems, it is more robust when coupled with an informed customer and a robust privacy program.

1. Voluntary Code of Conduct

As part of the current privacy program, the Companies actively participated in the creation of the U.S Department of Energy's January 2015 *Data Privacy and the Smart Grid: A Voluntary Code of Conduct* ("VCC"). Internal policies and practices are already being modified to allow for adoption of the VCC.. The code includes the following critical elements:

- *Customer Notice*: The Companies already have a strong Customer Information Privacy Policy available on all three company websites.[7] This policy has been revised to cover all customer data collected, regardless of the method of collection. Additionally, input from the Companies' Customer Service department has improved how the Comapies communicate using the policy to answer customer questions on data privacy.

- *Customer Choice and Consent*: With the additional data collected by smart meters, customers should decide how the data is used. The CFS proposed in the accompanying application contains robust requirements to allow customers to decide the level of data sharing and method of contact.

- *Customer Data Access*: Also integral to the VCC is the principle that customers should have access to their data. The proposed CFS will enhance this capability while continuing to participate in the Green Button Initiative, which allows current smart meter customers to download their usage data for sharing at their discretion.

2. Internal Information Resource Policies

As part of the processes already in place to protect information, the Companies have specific policies on Information Ownership and Information Classification. These policies explicitly describe the department responsible for classification of the data, and the level of protection appropriate for each classification. As part of the Initial Phase deployment, ownership of customer usage data was explicitly established with the Companies' Customer Service department to ensure the customer view is taken with regard to protection of customer usage data. This same process will be utilized for the SGF Project and beyond, with the added level of flexibility to ensure the Companies are maintaining customer expectations.

IV. CONCLUSION

The Companies understand and are vigilant about mitigating the potential risks posed by the implementation of Smart Grid 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 extensively prepared their operational configurations to accommodate the need for additional infrastructure required to protect against any unwarranted intrusion or cyber-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 SGF Project, there will be ongoing assessments, testing and evaluation of the services and processes in place to ensure

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[7] Available at http://www.hawaiianelectric.com/portal/site/heco/privacypolicy.

that changes in cybersecurity and privacy protection measures are kept current, and that all customer, legal and regulatory requirements are met or exceeded. As new threats or vulnerabilities surface the Companies will implement additional measures to accommodate the demands of their data management and privacy procedures, to ensure customer information is kept protected.

Exhibit E

Smart Grid Foundation Project

Vendor Selection

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Attachment 2 – Smart Meter Installation Request for Proposal

Attachment 3 – Smart Grid Meter Data Management System Request for Proposal

Attachment 4 – Smart Grid Customer Facing Solutions Request for Proposal

Attachment 5 – Websphere Enterprise Service Bus System Integrator Request for Proposal

Attachment 6 – Enterprise Data Warehouse Request for Proposal

For administrative convienience:

- Attachment 1 and Attachment 2 are located in Book 2 of 4 to the Application
- Attachment 3 and Attachment 4 are located in Book 3 of 4 to the Application
- Attachment 5 and Attachment 6 are located in Book 4 of 4 to the Application

VENDOR SELECTION

I. INTRODUCTION

In selecting the vendors who will furnish the Hawaiian Electric Companies[1] with hardware, equipment, third-party software and outside services for the Smart Grid Foundation Project ("SGF Project"), the Companies have struck a balance between the benefits of carrying out a formal bidding process and the efficiencies associated with leveraging existing experience and relationships. For the SGF Project, this approach has generally resulted in vendors being selected in one of three different approaches.

The general default approach was to select vendors through formal request for proposals ("RFPs") processes. For the SGF Project, vendors were selected through the RFP process in cases where the Companies had relatively little knowledge or experience with the products or services being solicited and/or where the potential purchase value of the contract was significant. Given the complexities and evolving nature of Smart Grid technologies, and also the challenges associated with carrying out eight RFP processes in a roughly six-month timeframe.[2] The Companies contracted with Navigant Consulting, Inc. ("Navigant") and Neptune Consulting Group, Inc. ("NCGI") to assist with the development of the RFPs, the management of the RFP process and to provide consulting expertise on the bidding vendors. Vendors for the following SGF Project products and services were selected through this RFP process:

- Smart Meters – [redacted]
- Meter Installation –
- Meter Data Management System ("MDMS") –
- Customer Facing Solutions ("CFS") –
- Enterprise Service Bus ("ESB") –
- Enterprise Data Warehouse ("EDW") –

Two of the SGF Project vendors (i.e., Silver Spring Networks, Inc. ("SSNI") and [redacted] were single-sourced based in part on the Companies' familiarity with the vendors and products they provide. In the case of SSNI, the Companies identified that vendor as the leading implementer of Advanced Metering Infrastructure in the nation. SSNI's proven track record in the industry rendered that vendor a highly desirable strategic partner by which the Companies will be able to have influence over the Smart Grid solutions that are ultimately implemented within their service territories.

In the case of [redacted] its [redacted] product is a state-of-the-art solution that provides CVR control utilizing smart meters and distribution field assets (i.e., load tap changers and capacitor banks). For the Companies' Smart Grid Initial Phase demonstration project on O'ahu ("Initial Phase"), SSNI recommended [redacted] product due in part to the fact that [redacted] has already

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[1] The "Hawaiian Electric Companies" or "Companies" are Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Maui Electric Company, Limited ("Maui Electric") and Hawaii Electric Light Company, Inc. ("Hawai'i Electric Light").

[2] Of the eight RFPs issued by the Companies, six resulted in awards and two (i.e., the RFPs for a prepayment solution and an advanced distribution management system) were cancelled. Copies of the six RFPs that resulted in awards are provided as attachments 1-6 of this Exhibit.

been integrated into SSNI's Advanced Metering Infrastructure ("AMI") network. In addition, the capabilities provided by [redacted] will enable the Companies to further leverage the existing SCADA that has been successfully installed and utilized in connection with Phase 2 of the Companies' East O'ahu Transmission Project and the Initial Phase, as further discussed in Section II.B.3.b.ii of Exhibit B to the accompanying Application.

In addition to the vendors, that were selected via the RFP process or single-sourced, a number of vendors for the SGF Project will be providing products and services pursuant to contracts that were in effect prior to the commencement of selection. Although this category of vendors includes more suppliers than it would be practicable to list here (for example the list would include vendors for poles, meter collars, office supplies, etc.), the following vendors are the primary SGF Project vendors that will be supplying the main products and services under existing contracts:

- [redacted] – The Companies' existing Outage Management System ("OMS") utilizes software and support provided by [redacted] The OMS subproject will expand the existing OMS system on O'ahu to Maui Electric and Hawai'i Electric Light. Utilizing a vendor other than [redacted] for this effort would result in the unnecessary incurrence of additional costs to select, implement and integrate a different system.

- [redacted] – The Companies existing vendors for Hawaiian Electric's EnergyScout ("EnergyScout") program are [redacted], which provides the direct load control ("DLC") switches) and Honeywell (which provides the installation, support and maintenance services). Utilizing different vendors for these items would result in the unnecessary incurrence of additional costs for vendor selection and training (since the existing vendors are already familiar with the program and customers), and also require customers to familiarize themselves with different product vendors and installers.

- [redacted] is the Companies' existing supplier of the digital capacitor bank controllers that enable the Companies to control capacitor banks on distribution circuits. [redacted] controls have been successfully used on existing [redacted] capacitor bank equipment on the Companies' systems. In addition, the Companies are receiving factory-direct pricing for the controllers. Utilizing a vendor other than [redacted] for this effort would result in the unnecessary incurrence of additional costs to select, validate and integrate to these existing capacitor bank equipment.

In each case where a SGF Project vendor has been selected outside of the traditional RFP process, the benefit of the selection (i.e., reduced costs to customers and faster development of the Companies' Smart Grid initiatives) has outweighed the need for a formal bidding process.

II. RFP AWARDS

As indicated above the general default approach to select vendors for the SGF Project was through the RFP process.

A. RFP PROCESS

In 2014, the Companies contracted with Navigant Consulting, Inc. ("Navigant") and Neptune Consulting Group, Inc. ("NCGI") to assist with the development of the RFPs and selection of vendors for the smart meters, meter installation services, MDMS, CFS, ESB and EDW. Identification of functional and technical requirements commenced with a series of meetings attended by stakeholders from across the Companies.

Selection Teams were established to finalize the functional, technical and future requirements of the various Smart Grid components and to evaluate the proposals that were received in response to the issued RFPs. The Selection Teams consisted of representation from the following departments within the Companies: System Operations, Engineering, Meter Engineering, Meter Shop, Customer Service, Field Operations, Call Center, Revenue Management, AMI Division, Digital Experience, Education and Customer Affairs, Corporate Communications, Community Relations, Enterprise Program Management Office, Information Technology Services, and Information Assurance, Legal and Purchasing.

Figure 1 below provides a high-level illustration of the RFP process as published in the RFPs. The number of vendors conducting on-site demonstrations varied based on the proposal evaluations.

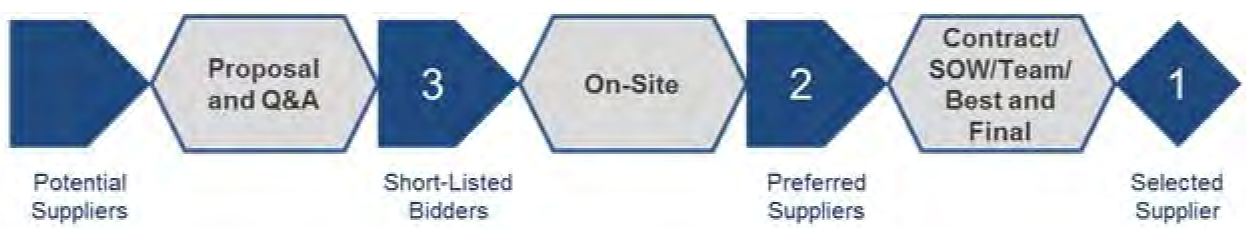

Figure 1: Bidder Overall and Category Scores

The RFP Process followed the schedule presented in Table 1, below.

RFP Event	Description
Mandatory Intent to Submit Bid and Mutual Non-Disclosure Agreement (“MNDA”) Forms	All interested vendors were required to submit an Intent to Submit Bid form and MNDA Form.
Questions for Bidders Conference	Bidders were given time to submit their questions for the Bidders Conference.
Bidder’s Conference	Conference call with all bidders to answer questions that were sent in advance. Questions received after the Bidder’s Conference were answered via email and copied to all bidders.
Bids Submitted	Bidders submit their bids via email, with hard copies physically mailed.
Short-Listed Bidder Presentations	The three short-listed bidders were invited to present at the Companies.
Best and Final Price Negotiations	The two finalists were invited to submit their best and final price.
Provisional Award (pending contract execution and decision and order enabling the project to commence)	The Selection Team makes their decision on the awardee and the provisional award is made to the vendor.

Table 1: Proposal Category Weighting

For each requirement listed in the RFP, bidders specified one of six ratings that described the capability of their proposed system/solution: (1) met standard; (2) will meet standard in scheduled upcoming release; (3) can meet standard using third-party products; (4) can meet standard with customization; (5) does not meet standard; or (6) other. Requirements not addressed by the bidder were given a rating of other or zero. Each bidder’s responses were evaluated based on the following weighting for each rating:

Requirements Rating	**Weight**
System as proposed meets standard	100%
System will meet standard in scheduled upcoming release	80%
System can meet standard using third-party products	60%
System can meet standard with customization	20%
System as proposed does not meet standard	0%
Other	0%

Table 2: Technical Requirements Rating and Weights

The following evaluation rubric was used to translate qualitative ratings into quantitative scores:

Rating Scale		
Exceptional	10	Bidder's proposal demonstrates an exceptional understanding of the goals and objectives of the RFP and significantly exceeds the requirements or offers a superior alternative. One or more major strengths exist. No major weaknesses exist. Strengths significantly outweigh the weaknesses. Expected to cause no disruption in schedule, increase in cost, or degradation in performance.
Very Good	7	Bidder's proposal demonstrates a very good level of understanding of the goals and objectives of the RFP, and somewhat exceeds the requirements or offers an acceptable alternative. Strengths outbalance weaknesses. Any weaknesses are easily correctable. Any weakness may cause minimal disruption of schedule, increase in cost or degradation of performance.
Good	4	Bidder's proposal demonstrates a good level of understanding of the goals and objectives of the RFP, and satisfies the requirements. There may be strengths or weaknesses, or both. Weaknesses are not offset by strengths, but the weaknesses do not significantly detract from the Bidder's response. Weaknesses are correctable. Any weakness may cause minimal to moderate disruption of schedule, increase in cost or degradation of performance.
Marginal	1	Bidder's proposal demonstrates a marginal level of understanding of the goals and objectives of the RFP and does not fully meet the requirements. The weaknesses found outweigh any strengths. Weaknesses will usually be difficult to correct. The weaknesses are expected to cause moderate to high disruption of schedule, increase in cost, or degradation in performance.
Unacceptabl	0	Bidder's proposal demonstrates a poor understanding of the goals and objectives of the RFP and does not meet the requirements. Weaknesses clearly outweigh any strengths. Weaknesses are expected to be very difficult to correct or are not correctable. The weaknesses present an extremely high risk to the success of the project and are expected to cause significant, serious disruption of schedule, increase in cost or degradation of performance.

Table 3: Rating Scale

B. <u>SMART METER RFP</u>

This RFP was used to select the providers of the specific smart meter products that are certified to communicate with the SSNI AMI infrastructure.

1. <u>Proposal Evaluation Criteria and Methodology</u>

The Companies' Smart Meter RFP Team reviewed and assessed each bidder proposal. Navigant compiled each bidder's total score in accordance with the criteria presented in Table 4 below:

Requirements	35%
Project Implementation	25%
Vendor Qualifications	20%
Pricing	20%

Table 4: Proposal Category Weighting

Each category (Requirements, Project Implementation, Vendor Qualifications and Pricing) consisted of sub-categories and their associated weights. Scores were calculated for each sub-category under the category to apply the weighting by the Smart Meter RFP Team.

Bidder responses to RFP Appendix D: Technical Requirements and Appendix E: Meter Requirements were computed identically. A total Requirements score was computed for each bidder. Scores were calculated for each sub-category, Functional and Technical, in accordance with the following weights:

Requirements	
Meter (Functional) Requirements	50%
Technical Requirements	50%

Table 5: Requirements Weighting

As explained in Section I.B.2 above, each bidder was required to specify one of six ratings that described their proposed solution. The Smart Meter RFP Team rated bidders' written responses to RFP questions regarding Implementation Requirements. A total Implementation Requirement score was calculated for each bidder. Total scores were calculated for each sub-category using the following weights:

Project Implementation	
Project Objectives	10%
General Approach	10%
Scope	10%
Proposed Timeline and Key Milestones	10%
Acceptance Process	10%
Equipment Fabrication and Configuration	10%
Project Tools and Templates	10%
Internal Knowledge Transfer and Transition	10%
Organizational Change Management	10%
Training	10%

Table 6: Project Implementation Requirements Weighting

The Smart Meter RFP Team rated bidders' written responses to RFP questions regarding Vendor Qualifications. A total Vendor Qualifications score was calculated for each bidder. Total scores were calculated for each sub-category using the following weights:

Vendor Qualifications	
General Qualifications	25%
Completeness	25%
Smart Meter Deployment History	25%
Reuse Knowledge	25%

Table 7: Vendor Qualifications Weighting

Pricing was included and considered at each phase of the selection process. A total pricing score was calculated for each bidder. Scores were calculated for each sub-category using the following weights:

Pricing	
Total Cost	20%
Baseline Meter Costs	20%
Feature Costs	20%
Travel Costs	20%
Warranty	20%

Table 8: Pricing Weighting

2. Results of Proposal Evaluations

Navigant compiled and ranked the scores for each bidder proposal and the results were presented to the Smart Meter RFP Team for discussion. The Smart Meter RFP Team noted that the results of the overall proposal rating left bidders clustered around overall scores of 5.9 and 7.4.

Vendor Ratings	
[redacted]	5.7
	7.4
	5.9
	5.9

Table 9: Bidder Overall and Category Scores

Figure 2 below presents each bidder's proposal score by category. [redacted] were the only two bidders to offer all requested meters.

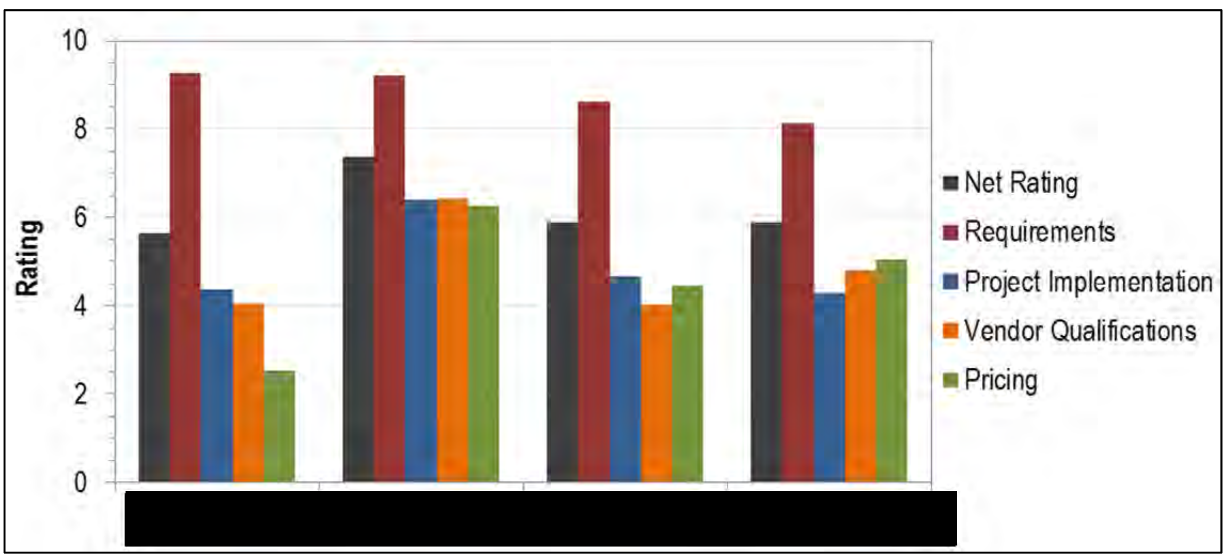

Figure 2: Bidder Overall and Category Scores

3. Final Selection

The Smart Meter RFP Team met to determine the final selection and was unable to down-select from two to one bidder. [redacted] were asked to submit their best and final offers. Prices varied from [redacted].

The Smart Meter RFP Team met to discuss the capabilities demonstrated by each bidder, the bidder's proposals and updated pricing. After careful deliberation, the Smart Meter RFP Team selected [redacted] as finalists. [redacted] was selected for the residential meters. [redacted] was selected for the commercial, industrial, time-of-use, and net energy metering (including grid supply and self-supply) meters. The final scores are shown in Table 10, below.

	Average	Weight	[redacted]	
		Net Rating		
Net Rating	**6.2**	100%	**7.4**	**5.9**
		Requirements		
Requirements	**8.8**	100%	**9.2**	**8.1**
Mandatory			**Provisional**	**Provisional**
Functional Requirements	8.8	100%	9	8
Mandatory			Provisional	Provisional
General Technology Reqs	6.9	0%	8	2
Mandatory			Provisional	Provisional
		Project Implementation		
Project Implementation	**4.9**	100%	**6.4**	**4.3**
Project Objectives	5.0	10%	6	5
General Approach	4.9	10%	7	4
Scope	4.7	10%	7	4
Proposed Timeline and Key Milestones	4.9	10%	7	3
Acceptance Process	5.4	10%	7	5
Equipment Fabrication and Configuration	5.4	10%	6	5
Project Tools and Templates	4.5	10%	6	4
Internal Knowledge Transfer and Transition	4.8	10%	7	5
Organizational Change Management	4.4	10%	6	3
Training	5.3	10%	7	4
		Vendor Qualifications		
Vendor Qualifications	**4.8**	100%	**6.4**	**4.8**
General Qualifications	5	25%	6	5
Completeness	5	25%	7	4
Smart Meter Deployment History	5	25%	7	7
Reuse Knowledge	4	25%	6	4
		Pricing		
Pricing	**4.6**	100%	**6.3**	**5.1**
Total Cost	4	20%	7	4
Baseline Meter Costs	5	20%	7	5
Feature Costs	5	20%	5	6
Travel Costs	4	20%	6	5
Warranty	5	20%	7	6

Table 10: Smart Meter Score

The Companies are negotiating with [redacted] to finalize the Goods Master Agreements ("GMA") with both companies. The Companies anticipate filing the executed GMAs by April 2016. If material matters arise in the negotiations that cannot be resolved, the Companies will look to other vendors, including re-evaluating the remaining short list bidders.

C. METER INSTALLATION

This RFP was used to select the provider who will supply the needed certified installation services for the smart meters.

1. Proposal Evaluation and Criteria Methodology

The Companies' Meter Installation RFP Team reviewed and assessed each bidder proposal. Navigant compiled each bidder's total score in accordance with the criteria presented below:

Requirements	35%
Project Implementation	25%
Vendor Qualifications	20%
Pricing	20%

Table 11: Proposal Category Weighting

Each category (Requirements, Project Implementation, Vendor Qualifications and Pricing) consisted of sub-categories and their associated weights. Scores were calculated for each sub-category under the category to apply the weighting by the Meter Installation RFP Team.

Bidder responses to RFP Appendix D: Technical Requirements and Appendix E: Installation Requirements were computed identically. A total Requirements score was computed for each bidder. Scores were calculated for each sub-category, Functional and Technical, in accordance with the following weights:

Requirements	
Installation (Functional) Requirements	50%
Technical Requirements	50%

Table 12: Requirements Weighting

As explained in Section I.B.2 above, each bidder was required to specify one of six ratings that described their proposed solution. The Meter Installation RFP Team rated bidders' written responses to RFP questions regarding Implementation Requirements. A total Implementation Requirement score was calculated for each bidder. Total scores were calculated for each sub-category using the following weights:

Project Implementation	
Project Objectives	7%
Project Management	7%
Change Control	7%
Quality Assurance Expectations	7%
General Approach	7%
Scope	7%
Proposed Timeline and Key Milestones	7%
Acceptance Process	7%
Equipment Fabrication and Configuration	7%
Project Tools and Templates	7%
Internal Knowledge Transfer and Transition	7%
Organizational Change Management	7%
Data Sharing	7%
Reporting	7%

Table 13: Project Implementation Requirements Weighting

The Meter Installation RFP Team rated the bidders' written responses to RFP questions regarding Vendor Qualifications. A total Vendor Qualifications score was calculated for each bidder. Total scores were calculated for each sub-category using the following weights:

Vendor Qualifications	
General Qualifications	17%
Completeness	17%
Installation History	17%
Project Managers	17%
Installation Resources	17%
Reuse Knowledge	17%

Table 14: Vendor Qualifications Weighting

In addition, a Pricing evaluation was performed by certain Meter Installation RFP Team members. Pricing scenarios were evaluated by the Meter Installation RFP Team in the context of the overall proposal rating, and was included and considered at each phase of the selection process, but did not figure prominently in the selection process until the final selection. As a result, the Meter Installation RFP Team focused more directly on evaluating bidders' Functional, Technical, Qualifications and Implementation Requirements. Pricing became a major factor after the short demonstrations when bidders with the capabilities to fulfill the Companies' Technical Requirements were identified. A total pricing score was calculated for each bidder. Scores were calculated for each sub-category using the following weights:

Pricing	
Total Cost	14%
Mobilization	14%
Equipment	14%
Inventory Management	14%
Labor – Unrestricted	14%
Labor – Union	14%
Labor – Hawai'i License	14%

Table 15: Price Weighting

In the RFP, bidders were requested to provide several pricing options for union and non-union labor, with designation as to Hawai'i-based resources and non-Hawai'i-based resources. The bidders were required to provide pricing options for:

1. Performing work with no restrictions on resources for doing the work;
2. Performing work if the Companies specified that unionized labor (an International Brotherhood of Electrical Workers-IBEW Local 1260) needed to be utilized; and
3. Performing work if the Companies specified that the labor utilized needed to have a Hawai'i Electricians License.

Pricing varied from [redacted]

2. <u>Results of Proposal Evaluation</u>

Navigant collected the scores for each bidder proposal and the results were presented to the Meter Installation RFP Team for discussion. The Meter Installation RFP Team noted that the results of the overall proposal rating varied greatly from 2.0 to 8.0.

Vendor Ratings	
[redacted]	2.0
[redacted]	8.0
[redacted]	5.2
[redacted]	7.5
[redacted]	5.0
[redacted]	1.8

Table 16: Bidder Overall and Category Scores

Figure 3 below presents each bidder's proposal score by category.

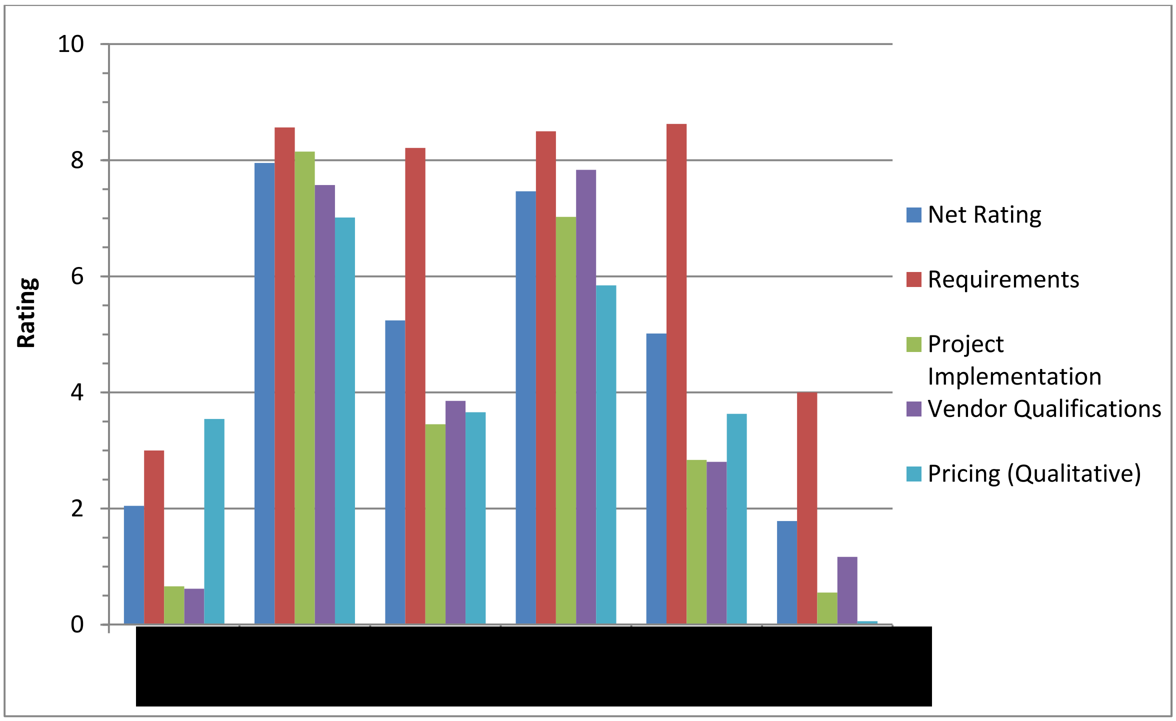

Figure 3: Bidder Overall and Category Scores

3. <u>Demonstrations</u>

To further evaluate certain bidder proposals and to address any potentially inflated responses, the Meter Installation Selection Team invited several bidders to provide a demonstration. [redacted] were asked to demonstrate the following items:

- Installation process flow;
- Tools and accelerators (work order, customer database, etc.);
- Project management approach; and
- Tools demonstration.

4. Final Selection

The Meter Installation Selection Team met to determine the final selection and was able to down-select from three to two bidders.

[redacted] were asked to submit their best and final offers with Hawai'i Union electricians. Prices varied from [redacted]

The Meter Installation Selection Team met to discuss the capabilities demonstrated by each bidder, the bidder's proposals and updated pricing. After careful deliberation, the Meter Installation Selection Team selected [redacted] The final scores are shown in Table 17, below.

	Average	Weight	[redacted]	
Net Rating				
Net Rating	**4.9**	100%	**8.0**	**7.5**
Requirements				
Requirements	**6.8**	100%	**8.6**	**8.5**
Mandatory			**Provisional**	**Pass**
Functional Requirements	7.0	50%	9	10
Mandatory			Provisional	Pass
General Technology Reqs	6.6	50%	8	7
Mandatory			Provisional	Pass
Project Implementation				
Project Implementation	**3.8**	100%	**8.1**	**7.0**
Project Objectives	4.6	7%	9	7
Project Management	3.8	7%	8	7
Change Control	3.4	7%	7	7
Quality Assurance Expectations	3.9	7%	9	7
General Approach	4.5	7%	9	8
Scope	4.1	7%	8	7
Proposed Timeline and Key Milestones	4.1	7%	8	7
Acceptance Process	3.2	7%	8	7
Equipment Fabrication and Configuration	4.0	7%	9	7
Project Tools and Templates	3.5	7%	9	5
Internal Knowledge Transfer and Transition	3.2	7%	8	7
Organizational Change Management	3.0	7%	6	7
Data Sharing	3.8	7%	9	8
Reporting	3.7	7%	8	7
Vendor Qualifications				
Vendor Qualifications	**4.0**	100%	**7.6**	**7.8**
General Qualifications	5	17%	8	8
Completeness	4	17%	7	8
Installation History	4	17%	10	9
Project Managers	4	17%	6	7
Installation Resources	4	17%	7	7
Reuse Knowledge	4	17%	8	8
Pricing				
Pricing (Qualitative)	**4.0**	100%	**7.0**	**5.8**
Total Cost	5	14%	9	6
Mobilization	4	14%	7	6
Equipment	4	14%	6	6
Inventory Mgmt	4	14%	6	7
Labor - Unrestricted	3	14%	4	7
Labor - Union	4	14%	9	5
Labor - HI License	4	14%	9	6

Table 17: Meter Installation Score

The Companies are negotiating with [redacted] to finalize the General Services Master Services Agreement ("GSMA") and the Statement of Work ("SOW"), which defines the required deliverables for the Meter Installation Project. The Companies anticipate filing an executed GSMA and SOW by April 2016. If material matters arise in the negotiations that cannot be resolved, the Companies will look to other vendors, including re-evaluating the remaining short list bidders.

D. METER DATA MANAGEMENT SYSTEM

This RFP was used to select the product and services needed to implement a MDMS that will integrate with the existing [redacted] customer information system and the SSNI AMI infrastructure.

1. Proposal Evaluation Criteria and Methodology

The MDMS Selection Team reviewed and assessed each bidder proposal. NCGI compiled each bidder's total score in accordance with the criteria presented below:

Requirements	35%
Project Implementation	25%
Vendor Qualifications	20%
Pricing	20%

Table 18: Proposal Category Weighting

Each category (Requirements, Project Implementation, Vendor Qualifications and Pricing) consisted of sub-categories and their associated weights. Scores were calculated for each sub-category under the category to apply the weighting by the MDMS Selection Team.

Bidder responses to RFP Appendix B: Functional and Technical Requirements and Appendix C: Technical Requirements were computed identically. A total requirements score was computed for each bidder. Scores were calculated for each sub-category, Functional, Technical and General Technology in accordance with the following weights:

Requirements	
Functional Requirements	**60%**
Technical Requirements	**20%**
General Technology Requirements	**20%**

Table 19: Requirements Weighting

As explained in Section I.B.2 above, each bidder was required to specify one of six ratings that described their proposed solution.

The MDMS Selection Team rated bidders' written responses to RFP questions regarding Vendor Qualifications ("Qualifications Requirements") according to the rubric in Table 3. A total Qualifications Requirement score was calculated for each bidder. Total scores were calculated for each sub-category using with the following weights:

Vendor Qualifications	
Supplied Information from Proposal	10%
Supplier Company Information	10%
Capabilities and Experience	10%
Customer References	10%
Future Technology Strategy	10%
5 Year Product Roadmap	10%
Proposed Supplier Team	2%
Key Personnel	2%
Offshore Capabilities	2%
Reuse Knowledge	2%
Internal Knowledge Transfer	2%
Commercial Terms	10%
Functional Demos	10%
Technical Demos	10%

Table 20: Vendor Qualifications Requirements Weighting

The MDMS Selection Team rated bidders' written responses to RFP questions regarding Implementation Requirements. A total Implementation Requirement score was calculated for each bidder. Total scores were calculated for each sub-category using the following weights:

Implementation Requirements	
Supplied Information from Proposal	5%
Soundness of Approach	5%
Scope (In/Out Matrix)	5%
Project Organization and Governance	5%
Project Management Approach	5%
Milestones/Deliverables/ Acceptance	5%
Risk/Issues/Change Control Approach	5%
SOX Compliance	5%
Proposed Schedule	5%
Roles and Responsibilities (RACI)	5%
Impact on Hawaiian Electric Resources (RACI)	5%
Project Staffing by Vendor (Staff Loading)	5%
Project Tools and Templates	5%
OCM	5%
Training Delivery	5%
Training Development	5%
Documentation	5%
Data Approach	5%
Testing Approach	5%
Operational Readiness	3%
Post-Go-Live Support	2%

Table 21: Project Implementation Requirements Weighting

In addition, a Pricing evaluation was performed by certain MDMS Selection Team members and NCGI. Pricing varied from [redacted].

Pricing scenarios were evaluated by the MDMS Selection Team in the context of the overall proposal rating, and was included and considered at each phase of the selection process, but did not figure prominently in the selection process until the final selection. As a result, the

MDMS Selection Team focused more directly on evaluating bidders' Technical, Qualifications and Implementation Requirements.

Pricing became a major factor after the short demonstrations when bidders with the capabilities to fulfill the Companies' Technical Requirements were identified. A total pricing score was calculated for each bidder.

2. Results of Proposal Evaluation

NCGI calculated and ranked the scores for each bidder proposal and the results were presented to the MDMS Selection Team for discussion. The overall proposal rating varied from 4.2 to 6.1.

Vendor Ratings	
[redacted]	6.1
[redacted]	5.7
[redacted]	5.2
[redacted]	5.5
[redacted]	4.4
[redacted]	4.2

Table 22: Bidder Overall and Category Scores

Figure 4, below shows each bidder's proposal score by category.

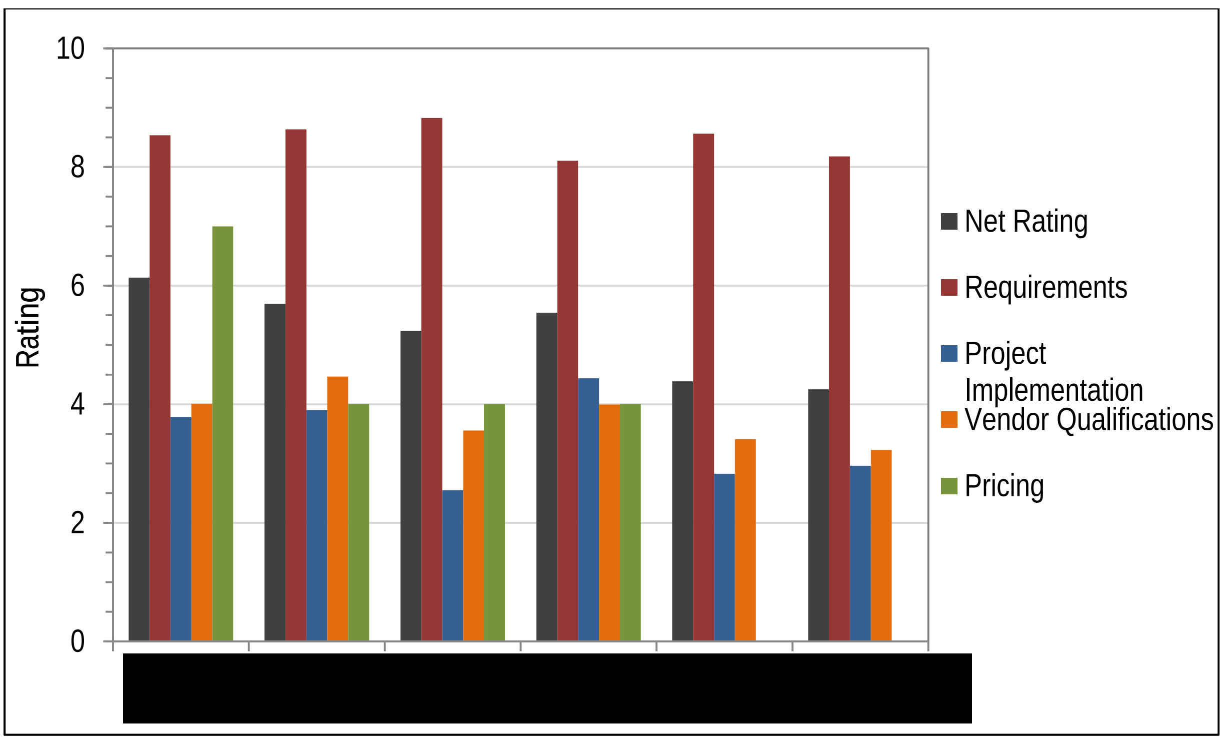

Figure 4: Bidder Overall and Category Scores

[redacted] received a score of "0" for pricing. [redacted] bid included a large number of customizations that resulted in a price that was well above the other bidders. [redacted] included very large third-party systems implementation costs. The responses from [redacted] and its integrator were conflicting.

3. Demonstrations

To further evaluate certain bidder proposals and to address any potentially inflated responses, the MDMS Selection Team invited several bidders to provide a demonstration. [redacted] were asked to showcase their products, and walk through the functional, technical, cybersecurity requirements fit and technical architecture. The vendors were asked to demonstrate the following capabilities:

1. How their tools present billing exceptions that require manual correction;
2. How their tools support the billing analyst in the correction of the exceptions/interval data in order to clear the exception;
3. How their tools support rebilling scenarios;
4. How their tools support viewing of Meter messages/communications; and
5. Dashboards or reports on system/billing health.

The demonstration agenda is included in the MDMS RFP.

4. Final Selection

The MDMS Selection Team met to determine the final selection and was unable to down-select from three to two bidders. All three finalists were asked to submit their best and final offers with a standardized release schedule. Prices varied from [redacted]

The MDMS Selection Team met to discuss the capabilities demonstrated by each system, the bidder's proposals and updated pricing. After careful deliberation, the MDMS Selection Team selected [redacted] The final scores are shown in Table 23**: MDMS Score**, below.

	Average	Weight	[redacted]		
Net Rating	**5.7**	100%	**5.8**	**6.2**	**5.2**
Requirements	8.7	100%	**9.1**	**8.4**	**8.6**
Functional Requirements	8.9	60%	9.4	8.4	8.9
Technical Requirements	9.6	20%	9.9	9.8	9.2
General Technology Reqs	7.3	20%	7.6	6.8	7.3
Project Implementation	3.8	100%	**2.8**	**4.4**	**4.1**
Supplied Information from Proposal	3.8	5%	3.1	3.3	5.0
Soundness of Approach	4.3	5%	3.7	4.3	5.0
Scope (In/Out Matrix)	2.8	5%	2.1	3.2	3.0
Project Organization and Governance	4.5	5%	3.4	5.0	5.0
Project Management Approach	4.6	5%	4.0	4.7	5.0
Milestones/Deliverables/ Accceptance	4.0	5%	3.6	4.3	4.0
Risk/Issues/Change Control Approach	4.9	5%	4.3	4.3	6.0
SOX Compliance	3.9	5%	1.7	5.0	5.0
Proposed Schedule	3.7	5%	3.0	5.0	3.0
Roles and Responsibilities (RACI)	3.3	5%	1.6	4.3	4.0
Impact on Hawaii Electric Resources (RACI)	3.2	5%	1.0	4.7	4.0
Project Staffing by Vendor (Staff Loading)	3.7	5%	3.4	3.7	4.0
Project Tools and Templates	3.8	5%	3.1	4.3	4.0
OCM	3.0	5%	1.4	4.7	3.0
Training Delivery	4.1	5%	3.1	5.3	4.0
Training Development	3.3	5%	2.8	4.0	3.0
Documentation	3.8	5%	3.1	4.3	4.0
Data Approach	3.9	5%	4.3	4.3	3.0
Testing Approach	3.5	5%	1.6	5.0	4.0
Operational Readiness	2.8	3%	1.4	4.0	3.0
Post-Go-Live Support	4.3	2%	3.7	3.3	6.0
Vendor Qualifications	4.7	100%	**5.5**	**4.1**	**4.7**
Supplied Information from Proposal	3.8	10%	3.1	3.3	5.0
Supplier Company Information	5.3	10%	4.5	5.3	6.0
Capabilities and Experience	5.5	10%	5.2	5.3	6.0
Customer References	5.0	10%	4.3	4.7	6.0
Future Technology Strategy	3.6	10%	4.3	2.6	4.0
5 Year Product Roadmap	3.8	10%	5.2	2.2	4.0
Proposed Supplier Team	3.1	2.0%	2.5	3.7	3.0
Key Personnel	2.4	2.0%	2.2	3.0	2.0
Offshore Capabilities	3.8	2.0%	2.1	5.3	4.0
Reuse Knowledge	4.1	2.0%	3.0	4.3	5.0
Internal Knowledge Transfer	3.9	2.0%	3.7	4.0	4.0
Commercial Terms	6.0	10%	10.0	4.0	4.0
Functional Demos	4.9	10%	5.6	5.0	4.0
Technical Demos	6.0	10%	10.0	4.0	4.0
Pricing	4.0	100%	**4.0**	**7.0**	**1.0**
Total Cost	4.0	100%	4.0	7.0	1.0

Table 23: MDMS Score

The Companies are negotiating with [redacted] to finalize the Technology Master Services Agreement ("TMSA") and SOW, which defines the required functionality and deliverables for the MDMS subproject. The Companies anticipate filing an executed TMSA and SOW by April 2016. If material matters arise in the negotiations that cannot be resolved, the Companies will look to other vendors, including re-evaluating the remaining short list bidders.

E. CUSTOMER FACING SOLUTION

This RFP was used to select the product and services to implement the web/mobile customer facing solution platform that will integrate with the existing [redacted] customer information system.

1. Proposal Evaluation Criteria and Methodology

The CFS Selection Team reviewed and assessed each bidder proposal. NCGI compiled each bidder's total score in accordance with the criteria presented below:

Requirements	35%
Project Implementation	25%
Vendor Qualifications	20%
Pricing	20%

Table 24: Proposal Category Weighting

Each category (Requirements, Project Implementation, Vendor Qualifications and Pricing) consisted of sub-categories and their associated weights. Scores were calculated for each sub-category under the category to apply the weighting by the CFS Selection Team.

Bidder responses to RFP Appendix C: Functional and Technical Requirements and Appendix D: Technical Requirements were computed identically. A total Requirements score was computed for each bidder. Scores were calculated for each sub-category, Functional, Technical and General Technology in accordance with the following weights:

Requirements	
Functional Requirements	60%
Technical Requirements	20%
General Technology Requirements	20%

Table 25: Requirements Weighting

As explained in Section I.B.2 above, each bidder was required to specify one of six ratings that described their proposed solution.

The CFS Selection Team rated bidders' written responses to RFP questions regarding Qualifications Requirements according to the rubric in Table 3. A total Qualifications Requirement score was calculated for each bidder. Total scores were calculated for each sub-category using the following weights:

Vendor Qualifications	
Supplied Information from Proposal	10%
Supplier Company Information	10%
Capabilities and Experience	10%
Customer References	10%
Future Technology Strategy	10%
5 Year Product Roadmap	10%
Proposed Supplier Team	10%
Key Personnel	10%
Offshore Capabilities	10%
Reuse Knowledge	5%
Internal Knowledge Transfer	5%

Table 26: Vendor Qualifications Requirements Weighting

The CFS Selection Team rated bidders' written responses to RFP questions regarding Implementation Requirements. A total Implementation Requirement score was calculated for each bidder. Total scores were calculated for each sub-category using the following weights:

Implementation Requirements	
Supplied Information from Proposal	5%
Soundness of Approach	5%
Scope (In/Out Matrix)	5%
Project Organization and Governance	5%
Project Management Approach	5%
Milestones/Deliverables/ Acceptance	5%
Risk/Issues/Change Control Approach	5%
SOX Compliance	5%
Proposed Schedule	5%
Roles and Responsibilities (RACI)	5%
Impact on Hawaiian Electric Resources (RACI)	5%
Project Staffing by Vendor (Staff Loading)	5%
Project Tools and Templates	5%
OCM	5%
Training Delivery	5%
Training Development	5%
Documentation	5%
Data Approach	5%
Testing Approach	5%
Operational Readiness	3%
Post-Go-Live Support	2%

Table 27: Project Implementation Requirements Weighting

In addition, a Pricing evaluation was performed by certain CFS Selection Team members and NCGI. Pricing varied from [redacted]. Pricing scenarios were evaluated by the CFS Selection Team in the context of the overall proposal rating, and included and considered at each phase of the selection process, but did not figure prominently in the selection process until the final selection. As a result, the CFS Selection Team focused more directly on evaluating bidders' Technical, Qualifications and Implementation Requirements. Pricing became a major factor after the short demonstrations when bidders with the capabilities to fulfill the Companies' Technical Requirements were identified. A total pricing score was calculated for each bidder.

2. <u>Results of Proposal Evaluation</u>

NCGI calculated and ranked the scores for each bidder proposal and the results were presented to the CFS Selection Team for discussion. The overall proposal rating varied widely from 4.6 to 7.1.

Vendor Ratings	
[redacted]	7.1
	6.4
	6.3
	5.8
	5.6
	5.3
	5.2
	5.0
	4.6

Table 28: Bidder Overall and Category Scores

Figure 5 below presents each bidder's proposal score by category.

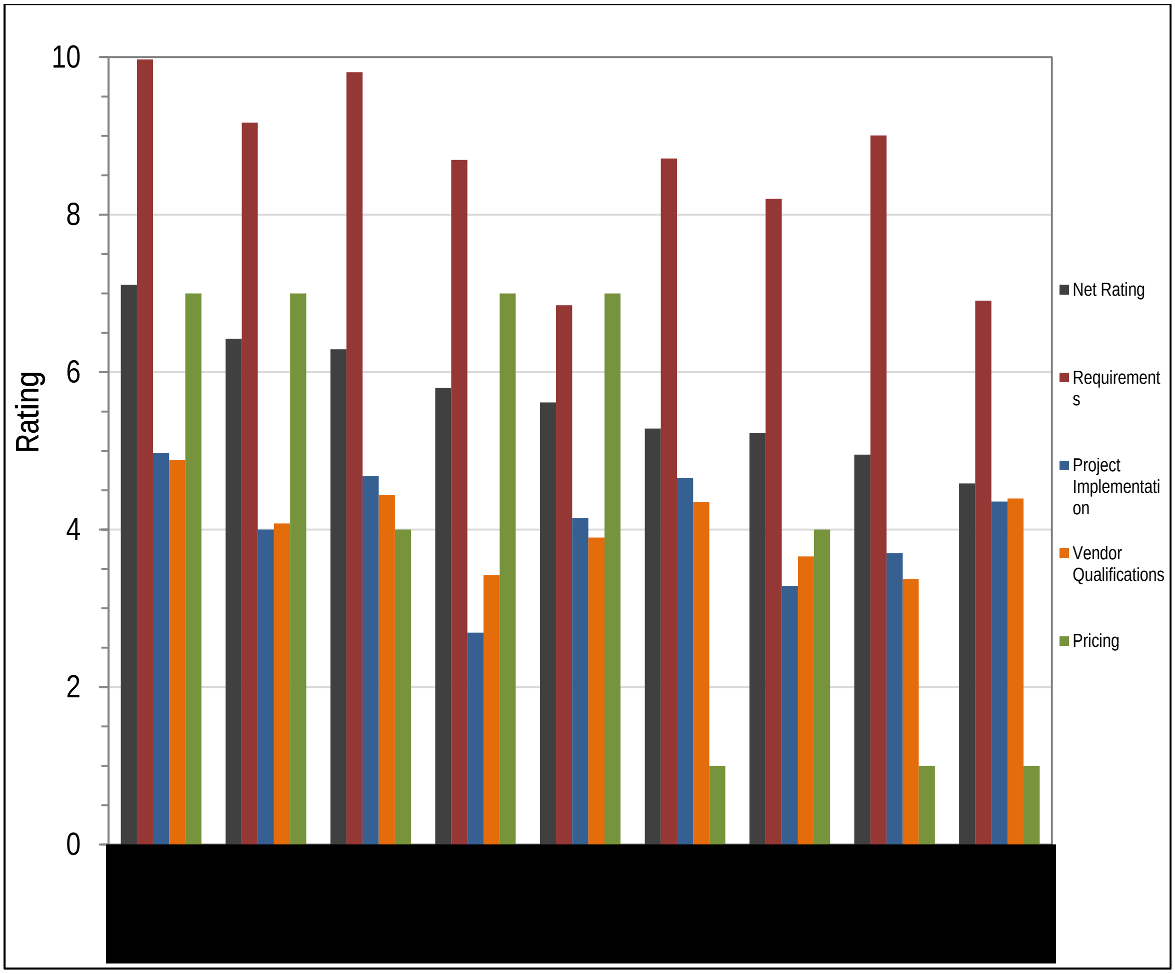

Figure 5: Bidder Overall and Category Scores

3. **Demonstrations**

To further evaluate certain bidder proposals and to address any potentially inflated responses, the CFS Selection Team invited several bidders to provide a demonstration. [redacted] were asked to showcase their products, and walk through the functional, technical, cybersecurity requirements fit and technical architecture. The vendors were asked to demonstrate the following scenarios:

1. Ability for a customer to register/sign-up for the portal;
2. Ability for a customer to view their interval usage

   (day/week/month/previous billing period);
3. Ability for a customer to view their bill;
4. Ability for a customer to make an online payment;
5. Ability for a customer to report an outage;
6. Ability for a customer to request move-in;

7. Ability for a customer to request move-out;
8. Ability for a customer to enroll in a program;
9. Ability for a customer to manage contact preferences and to opt-in/opt-out of a program;
10. All of the above on a mobile device;
11. All of the above when the user is a customer service representative trying to help the customer;
12. Reporting/dashboards; and
13. Web administrator tools.

The demonstration agenda is included in the CFS RFP.

4. Final Selection

The CFS Selection Team met to down-select from three to two bidders. [redacted] were asked to submit their best and final offers with a standardized release schedule. Prices varied from [redacted]

The CFS Selection Team met to discuss the capabilities demonstrated by each system, the bidder's proposals and updated pricing. After careful deliberation, the CFS Selection Team selected [redacted] The final scores are shown in Table 29**: CFS Score**, below.

	Average	Weight	[redacted]	
Net Rating	**5.7**	**100%**	**7.1**	**6.3**
Requirements	**8.6**	**100%**	**10.0**	**9.8**
Functional Requirements	8.6	60%	10	10
Technical Requirements	8.5	20%	10	10
General Technology Reqs	8.6	20%	10	9
Project Implementation	**4.0**	**100%**	**5.0**	**4.7**
Supplied Information from Proposal	4.2	5%	5	4
Soundness of Approach	4.6	5%	5	5
Scope (In/Out Matrix)	3.9	5%	7	6
Project Organization and Governance	4.6	5%	5	5
Project Management Approach	4.6	5%	5	5
Milestones/Deliverables/ Accceptance	4.3	5%	4	6
Risk/Issues/Change Control Approach	4.0	5%	4	5
SOX Compliance	4.4	5%	7	6
Proposed Schedule	3.7	5%	4	4
Roles and Responsibilities (RACI)	3.4	5%	4	5
Impact on Hawaii Electric Resources (RACI)	3.2	5%	5	4
Project Staffing by Vendor (Staff Loading)	3.4	5%	5	5
Project Tools and Templates	4.8	5%	6	5
OCM	4.4	5%	6	2
Training Delivery	3.4	5%	4	4
Training Development	3.5	5%	5	5
Documentation	2.6	5%	4	2
Data Approach	4.0	5%	5	5
Testing Approach	4.7	5%	5	6
Operational Readiness	4.0	3%	5	4
Post-Go-Live Support	3.7	2%	6	5
Vendor Qualifications	**4.0**	**100%**	**4.9**	**4.4**
Supplied Information from Proposal	4	10%	5	4
Supplier Company Information	5	10%	5	4
Capabilities and Experience	5	10%	5	4
Customer References	4	10%	5	4
Future Technology Strategy	3	10%	5	5
5 Year Product Roadmap	3	10%	6	6
Proposed Supplier Team	4	10%	4	4
Key Personnel	4	10%	4	4
Offshore Capabilities	4	10%	5	4
Reuse Knowledge	4	5%	5	4
Internal Knowledge Transfer	4	5%	4	4
Pricing	**4.8**	**100%**	**7.0**	**4.0**
Total Cost	5	100%	7	4

Table 29: CFS Score

The Companies are negotiating with [redacted] to finalize the TMSA and SOW, which defines the required functionality and deliverables for the CFS Project. The Companies anticipate filing an executed TMSA and SOW by April 2016. If material matters arise in the negotiations that cannot be resolved, the Companies will look to other vendors, including re-evaluating the remaining short list bidders.

F. ENTERPRISE SERVICE BUS

This RFP was used to select the product and services to enhance and extend the existing IBM Websphere solution in order to support the new Smart Grid systems.

1. Proposal Evaluation Criteria and Methodology

The ESB Selection Team reviewed and assessed each bidder proposal. NCGI compiled each bidder's total score in accordance with the criteria presented below:

Category	Weight
Scope and Deliverables	10%
Proposed Strategy and Technical Architecture	20%
Implementation Methodology and Approach	15%
Application Management Services	15%
Project Management Approach	5%
Proposed Project Organization	10%
Supplier Capabilities	10%
Pricing and Contracts	15%

Table 30: Proposal Category Weighting

Each category (Scope & Deliverables, Proposed Strategy and Technical Architecture, Implementation Methodology and Approach, Application Management Services, Project Management Approach, Proposed Project Organization, Supplier Capabilities, and Pricing & Contracts) consisted of sub-categories and their associated weights. Scores were calculated for each sub-category under the category to apply the weighting by the ESB Selection Team.

The ESB Selection Team rated bidders' written responses to RFP questions regarding Scope and Deliverables according to the rubric in Table 3. A total Scope and Deliverables score was calculated for each bidder. Total scores were calculated for each sub-category using the following weights:

Scope and Deliverables	
Scope and Deliverables	25%
In-Scope/Out-of-Scope Matrix	25%
Integration Services Methodology	25%
Mitigation of scope gaps	25%

Table 31: Scope and Deliverables Weighting

The ESB Selection Team rated bidders' written responses to RFP questions regarding Proposed Strategy and Technical Architecture according to the rubric in Table 3. A total Proposed Strategy and Technical Architecture score was calculated for each bidder.

Proposed Strategy and Technical Architecture	
Proposed Strategy and Technical Architecture	100%

Table 32: Proposed Strategy and Technical Architecture Weighting

The ESB Selection Team rated bidders' written responses to RFP questions regarding Implementation Methodology and Approach. A total Implementation Requirement score was calculated for each bidder. Total scores were calculated for each sub-category using the following weights:

Implementation Methodology and Approach	
Timeline and Milestones with Deliverables	20%
Acceptance Process	5%
Offshore Capabilities	15%
Reusability	10%
Project Tools and Templates	10%
Internal Knowledge Transfer	5%
Data Standardization	10%
Testing Methodology	10%
Operational Readiness	5%
Operational Process Baseline	0%
Post-Go-Live Support	10%
Training Delivery	0%
Training Development	0%

Table 33: Implementation Methodology and Approach Weighting

The ESB Selection Team rated bidders' written responses to RFP questions regarding Application Management Services. A total Application Management Services score was calculated for each bidder.

Application Management Services	
Application Management Services Approach	100%

Table 34: Production Support Weighting

The ESB Selection Team rated bidders' written responses to RFP questions regarding Project Management Support. A total Project Management Support score was calculated for each bidder. Total scores were calculated for each sub-category using the following weights:

Project Management Support	
Project Management Methodology	35%
Integrated Project Management Plan	35%
Project Status, Metrics and Reporting	13%
Risk Management	2%
Issues Management	2%
Project Management Change Control	3%
Sarbanes-Oxley (SOX) Compliance	10%

Table 35: Project Management Support Weighting

The ESB Selection Team rated bidders' written responses to RFP questions regarding Proposed Project Organization. A total Proposed Project Organization score was calculated for each bidder. Total scores were calculated for each sub-category using the following weights:

Proposed Project Organization	
Project Organization Chart	15%
Roles and Responsibilities (RASCI)	55%
Proposed Bidder Project Team	25%
Commitment to Resource Approval, SME Availability, Resource Transition Period and Work Hours	5%

Table 36: Proposed Project Organization Weighting

The ESB Selection Team rated bidders' written responses to RFP questions regarding Supplier Capabilities. A total Supplier Capabilities score was calculated for each bidder. Total scores were calculated for each sub-category using the following weights:

Supplier Capabilities	
Company Overview Aligns with HEI needs	10%
References and Related Engagements	25%
Production Experience with electric utilities	25%
Production Experience with IBM WebSphere	25%
Knowledge of OTS integrations for SG/IBM	15%

Table 37: Supplier Capabilities Weighting

The ESB Selection Team rated bidders' written responses to RFP questions regarding Pricing and Contracts. A total Pricing and Contracts score was calculated for each bidder. Total scores were calculated for each sub-category using the following weights:

Pricing and Contracts	
Total Cost	70%
Resource Rates/Proposed Rate Lock/Cap	10%
Attractiveness of Risk/Gain Sharing Approach	5%
TMSA/Contract Structure	15%

Table 38: Pricing and Contracts Weighting

In addition, a Pricing evaluation was performed by certain ESB Selection Team members and NCGI. Pricing varied from [redacted]. Pricing scenarios were evaluated by the ESB Selection Team in the context of the overall proposal rating, and included and considered at each phase of the selection process, but did not figure prominently in the selection process until the final selection.

Pricing became a major factor after the short demonstrations when bidders with the capabilities to fulfill the Companies' Technical Requirements were identified. A total pricing score was calculated for each bidder.

2. <u>**Results of Proposal Evaluation**</u>

NCGI calculated and ranked the scores for each bidder proposal and the results were presented to the ESB Selection Team for discussion. The overall proposal rating varied narrowly from 3.9 to 5.1.

Vendor Ratings	
[redacted]	5.0
	5.0
	4.1
	5.1
	3.9

Table 39: Bidder Overall and Category Scores

Figure 6 below presents each bidder's proposal score by category.

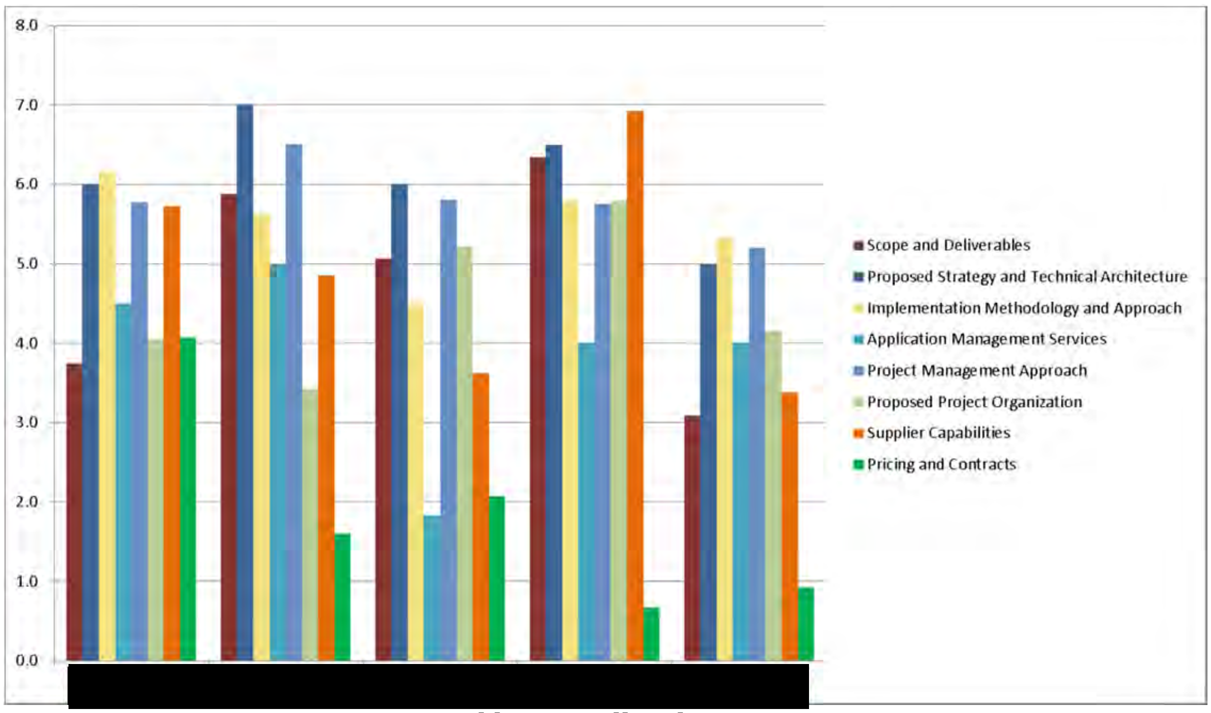

Figure 6: Bidder Overall and Category Scores

3. <u>Demonstrations</u>

To further evaluate certain bidder proposals and to address any potentially inflated responses, the ESB Selection Team invited several bidders to provide a demonstration. [redacted] were asked to demonstrate the following:

1. Company Briefing and Services Strategic Roadmap;
2. High-Level Understanding of the scope and deliverables;
3. Proposed ESB Strategy, Approach and Process;
4. Proposed ESB Technical Design, Standards and Maturity Process;
5. Implementation Approach and Services;
6. Support and Maintenance Services;

7. Recommended Staffing Models with Flexibility to Scale; and
8. Review of Cost Models and Options.

4. Final Selection

The ESB Selection Team met to down-select from three to two bidders. [redacted] were asked to submit their best and final offers. Prices varied from [redacted]

The ESB Selection Team met to discuss the capabilities demonstrated by each system, the bidder's proposals and updated pricing. After careful deliberation, the ESB Selection Team selected [redacted]. The final scores are shown in Table 40**: Enterprise Service Bus Score**, below.

	Average	Weight	[redacted]	
Net Score	4.9	100%	5.3	5.2
Scope and Deliverables	5.3	100%	5.9	6.3
Scope and Deliverables	5.5	25%	6.0	6.4
In-Scope/Out-of-Scope Matrix	4.8	25%	5.5	5.5
Integration Services Methodology	5.5	25%	5.5	7.0
Mitigation of scope gaps	5.5	25%	6.5	6.5
Proposed Strategy and Technical Architecture	6.5	100%	7.0	6.5
Proposed Strategy and Technical Architecture	6.5	100%	7.0	6.5
Implementation Methodology and Approach	5.9	100%	5.6	5.8
Timeline and Milestones with Delverables	5.7	20%	5.0	5.5
Acceptance Process	4.8	5%	5.5	5.5
Offshore Capabilities	6.7	15%	6.0	7.5
Reusability	6.2	10%	7.0	4.0
Project Tools and Templates	5.3	10%	4.5	6.0
Internal Knowledge Transfer	4.8	5%	5.0	4.5
Data Standardization	6.3	10%	6.0	6.5
Testing Methodology	6.5	10%	6.5	6.5
Operational Readiness	4.5	5%	3.0	4.5
Operational Process Baseline	4.5	0%	5.0	5.0
Post-Go-Live Support	5.8	10%	6.5	5.5
Training Delivery	5.7	0%	5.5	5.0
Training Development	4.7	0%	5.0	4.0
Application Management Services	4.5	100%	5.0	4.0
Application Management Services Approach	4.5	100%	5.0	4.0
Project Management Approach	6.0	100%	6.5	5.8
Project Management Methodology	6.3	35%	7.0	6.0
Integrated Project Management Plan	6.2	35%	6.5	6.0
Project Status, Metrics and Reporting	6.2	13%	6.0	6.0
Risk Management	5.8	2%	5.5	6.5
Issues Management	4.7	2%	5.0	4.0
Project Management Change Control	5.8	3%	6.5	5.5
Sarbanes-Oxley (SOX) Compliance	4.5	10%	6.0	4.0
Proposed Project Organization	4.4	100%	3.4	5.8
Project Organization Chart	5.2	15%	5.5	6.0
Roles and Responsibilities (RACI)	3.8	55%	2.0	5.5
Proposed Bidder Project Team	5.0	25%	5.0	6.0
Commitment to.... Resource Approval SME Availability Resource Transition Period Work Hours	5.8	5%	5.0	7.5
Supplier Capabilities	5.8	100%	4.9	6.9
Company Overview Aligns with HEI needs	6.2	10%	5.0	7.5
References and Related Engagements	5.0	25%	5.0	3.5
Production Experience with electric utilities	6.3	25%	5.5	7.5
Production Experience with IBM WebSphere	6.3	25%	4.5	9.5
Knowledge of OTS integrations for SG/IBM	5.3	15%	4.0	7.0
Pricing and Contracts	3.3	100%	4.2	1.5
Total Cost	3.0	70%	4.0	1.0
Resource Rates/Proposed Rate Lock/Cap	4.8	10%	5.0	4.5
Attractiveness of Risk/Gain Sharing Approach	4.3	5%	5.0	4.5
CMSA/Contract Structure	3.0	15%	4.0	1.0
Orals	5.2	100%	6.2	5.9

Table 40: Enterprise Service Bus Score

The Companies are negotiating with [redacted] to finalize the TMSA and SOW, which defines the required functionality and deliverables for the ESB subproject. The Companies anticipate filing an executed TMSA and SOW by April 2016. If material matters arise in the negotiations that cannot be resolved, the Companies will look to other vendors, including re-evaluating the remaining short list bidders.

G. ENTERPRISE DATA WAREHOUSE

This RFP was used to select the product and services to enhance and extend the existing data warehouse capabilities as well as to add additional product solutions that are able to support the large volumes of unstructured data.

1. Proposal Evaluation Criteria and Methodology

The EDW Selection Team reviewed and assessed each bidder proposal. NCGI compiled each bidder's total score in accordance with the criteria presented below:

Scope and Deliverables	15%
Implementation Methodology and Approach	20%
Production Support	15%
Project Management Approach	10%
Proposed Project Organization	10%
Supplier Capabilities	15%
Pricing and Contracts	15%

Table 41: Proposal Category Weighting

Each category (Scope & Deliverables, Implementation Methodology and Approach, Production Support, Project Management Approach, Proposed Project Organization, Supplier Capabilities, and Pricing & Contracts) consisted of sub-categories and their associated weights. Scores were calculated for each sub-category under the category to apply the weighting by the EDW Selection Team.

As explained in Section I.B.2 above, each bidder was required to specify one of six ratings that described their proposed solution. The EDW Selection Team rated bidders' written responses to RFP questions regarding Scope and Deliverables according to the rubric in Table 3. A total Scope and Deliverables score was calculated for each bidder. Total scores were calculated for each sub-category using with the following weights:

Scope and Deliverables	
Scope and Deliverables (overall)	20%
Requirements Collection	10%
EDW Design & Timeline	10%
Data Platform Development	15%
Detailed Delivery – by System	15%
Documentation	10%
Staff Development and Training	10%
Mitigation of scope gaps	10%

Table 42: Scope and Deliverables Weighting

The EDW Selection Team rated bidders' written responses to RFP questions regarding Implementation Methodology and Approach. A total Implementation Requirement score was calculated for each bidder. Total scores were calculated for each sub-category using the following weights:

Implementation Methodology and Approach	
Timeline and Milestones with Deliverables	20%
Acceptance Process	5%
Offshore Capabilities	15%
Reusability	10%
Project Tools and Templates	10%
Internal Knowledge Transfer	5%
Data Standardization/Cleansing/Migration	15%
Testing Methodology	15%
Operational Readiness	5%

Table 43: Implementation Methodology and Approach Weighting

The EDW Selection Team rated bidders' written responses to RFP questions regarding Production Support. A total Production Support score was calculated for each bidder.

Production Support	
Production Support Approach	100%

Table 44: Production Support Weighting

The EDW Selection Team rated bidders' written responses to RFP questions regarding Project Management Support. A total Project Management Support score was calculated for each bidder. Total scores were calculated for each sub-category using the following weights:

Project Management Support	
Project Management Methodology	35%
Integrated Project Management Plan	35%
Project Status, Metrics and Reporting	10%
Risk/Issue/Change Control Management	10%
Sarbanes-Oxley (SOX) Compliance	10%

Table 45: Project Management Support Weighting

The EDW Selection Team rated bidders' written responses to RFP questions regarding Proposed Project Organization. A total Proposed Project Organization score was calculated for each bidder. Total scores were calculated for each sub-category using the following weights:

Proposed Project Organization	
Project Organization Chart	15%
Roles and Responsibilities (RASCI)	55%
Proposed Bidder Project Team	25%
Commitment to Resource Approval, SME Availability, Resource Transition Period and Work Hours	5%

Table 46: Proposed Project Organization Weighting

The EDW Selection Team rated bidders' written responses to RFP questions regarding Supplier Capabilities. A total Supplier Capabilities score was calculated for each bidder. Total scores were calculated for each sub-category using the following weights:

Supplier Capabilities	
Company Overview Aligns with HEI needs	10%
References and Related Engagements	20%
Future Technology Strategy and Plan	10%
Experience with ESB, IBM WebSphere MQ/Message Broker/Integration Bus	5%
Experience with SAP ECC 6.0 EhP 7, CRM 7.0 EhP 3, and UCES 6.35	5%
Experience with PL/SQL or other programming languages	25%
Experience with "Big Data" systems, including Hadoop and non-Hadoop-based architectures (i.e., GreenPlum)	25%

Table 47: Supplier Capabilities Weighting

The EDW Selection Team rated bidders' written responses to RFP questions regarding Pricing and Contracts. A total Pricing and Contracts score was calculated for each bidder. Total scores were calculated for each sub-category using the following weights:

Pricing and Contracts	
Resource Rates/Proposed Rate Lock/Cap	10%
Attractiveness of Risk/Gain Sharing Approach	5%
Total Cost	70%
TMSA/Contract Structure	15%

Table 48: Pricing and Contracts Weighting

In addition, a Pricing evaluation was performed by certain EDW Selection Team members and NCGI. Pricing varied from [redacted]. Pricing scenarios were evaluated by the EDW Selection Team in the context of the overall proposal rating, and included and considered at each phase of the selection process, but did not figure prominently in the selection process until the final selection. Pricing became a major factor after the short demonstrations when bidders with the capabilities to fulfill the Companies' Technical Requirements were identified. A total pricing score was calculated for each bidder.

2. <u>Results of Proposal Evaluation</u>

NCGI calculated and ranked the scores for each bidder proposal and the results were presented to the EDW Selection Team for discussion. The overall proposal rating varied narrowly from 4.0 to 4.9.

Vendor	[redacted]					
Net Score	4.6	4.8	4.0	4.9	4.5	4.9

Table 49: Bidder Overall and Category Scores

Figure 7 below presents each bidder's proposal score by category.

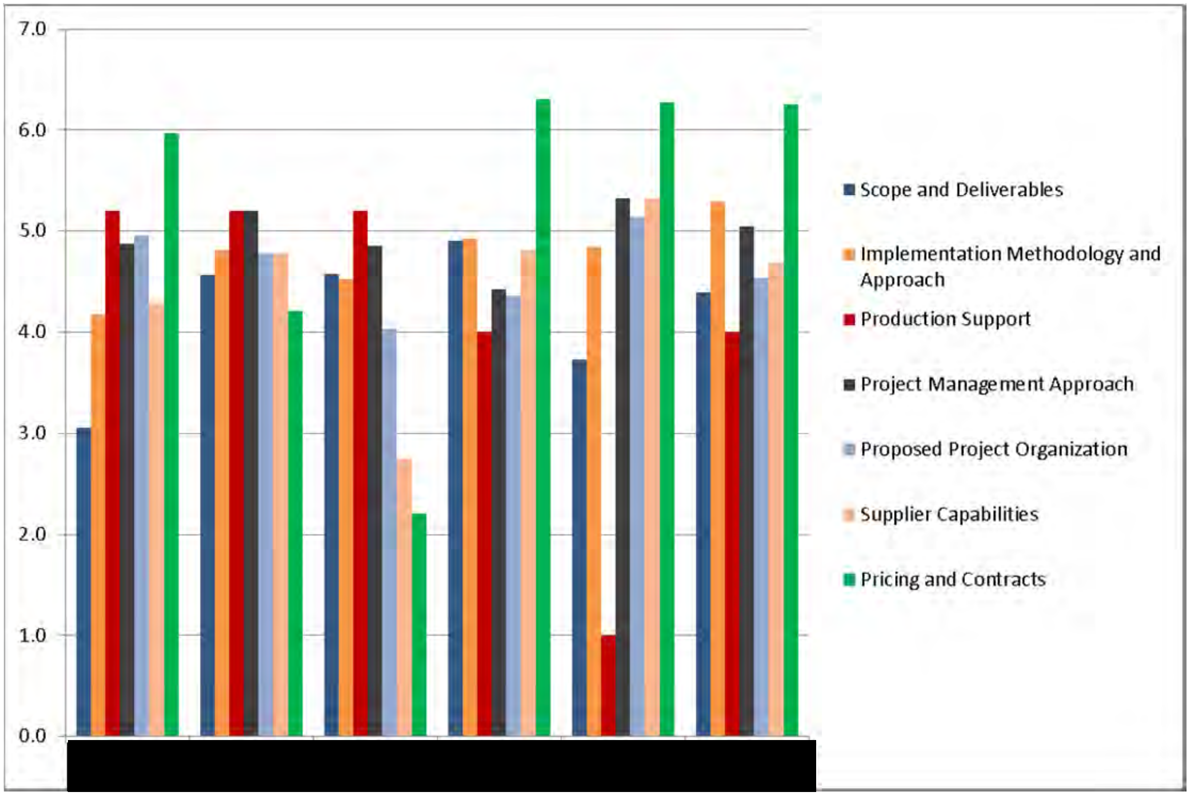

Figure 7: Bidder Overall and Category Scores

3. <u>Demonstrations</u>

To further evaluate certain bidder proposals and to address any potentially inflated responses, the EDW Selection Team invited several bidders to provide a demonstration. [redacted] were asked to demonstrate the following:

1. Company briefing and services strategic roadmap;
2. High-level understanding of the scope and deliverables;
3. Proposed EDW strategy, approach and process;
4. Proposed EDW technical design, standards and maturity process;
5. Implementation approach and services;
6. Support and maintenance services;
7. Recommended staffing models with flexibility to scale; and

8. Review of cost models and options.

4. **Final Selection**

The EDW Selection Team met to down-select from four to two bidders. [redacted] were asked to submit their best and final offers for On-Premises and Cloud hosting scenarios. Prices for On-Premises varied from $12.5 million to $13 million, and the hosted Cloud solution varied from [redacted]

The EDW Selection Team met to discuss the capabilities demonstrated by each system, the bidder's proposals and updated pricing. After careful deliberation, the EDW Selection Team selected [redacted] The final scores are shown in Table 50, below.

	Average	Weight	[redacted]	
Scope and Deliverables	**4.7**	**100%**	**4.6**	**4.9**
Scope and Deliverables (overall)	5	20%	5	5
Requirements Collection	5	10%	5	5
EDW Design & Timeline	5	10%	5	6
Data Platform Development	5	15%	5	5
Detailed Delivery – by System	5	15%	4	5
Documentation	5	10%	5	4
Staff Development and Training	4	10%	3	5
Mitigation of scope gaps	4	10%	4	4
Approach	**4.9**	**100%**	**4.8**	**4.9**
Timeline and Milestones with Deliverables	5	20%	4	5
Acceptance Process	6	5%	5	6
Offshore Capabilities	6	15%	6	5
Reusability	4	10%	5	3
Project Tools and Templates	4	10%	5	4
Internal Knowledge Transfer	4	5%	4	5
Data Standardization/Cleansing/Migration	6	15%	6	6
Testing Methodology	5	15%	4	5
Operational Readiness	4	5%	5	4
Operational Process Baseline	4	0%	4	4
Training Delivery	5	0%	5	5
Training Development	4	0%	4	5
Production Support	**4.6**	**100%**	**5.2**	**4.0**
Production Support Approach	5	100%	5	4
Project Management Approach	**4.8**	**100%**	**5.2**	**4.4**
Project Management Methodology	5	35%	5	5
Integrated Project Management Plan	5	35%	5	5
Project Status, Metrics and Reporting	5	10%	5	4
Risk/Issue/Change Control Management	5	10%	6	4
Sarbanes-Oxley (SOX) Compliance	4	10%	5	4
Proposed Project Organization	**4.6**	**100%**	**4.8**	**4.4**
Project Organization Chart	4	15%	5	4
Roles and Responsibilities (RASCI)	5	55%	5	5
Proposed Bidder Project Team	4	25%	4	4
Commitment to.... Resource Approval SME Availability Resource Transition Period Work Hours	5	5%	5	5
Supplier Capabilities	**4.8**	**100%**	**4.8**	**4.8**
Company Overview Aligns with HEI needs	5	10%	5	5
References and Related Engagements	4	20%	5	3
Future Technology Strategy and Plan	5	10%	5	5
Experience with ESB, IBM WebSphere MQ/Message Broker/Integration Bus	6	5%	5	6
Experience with SAP ECC 6.0 EhP 7, CRM 7.0 EhP 3, and UCES 6.35	3	5%	3	3
Experience with PL/SQL or other programming	5	25%	5	5
Experience with "Big Data" systems, including Hadoop and non-Hadoop-based architectures. (i.e. GreenPlum)	6	25%	5	6
Pricing and Contracts	**6.0**	**100%**	**4.9**	**7.0**
Resource Rates/Proposed Rate Lock/Cap	5	10%	5	5
Attractiveness of Risk/Gain Sharing Approach	4	5%	4	4
Total Cost	7	70%	5	8
CMSA/Contract Structure	5	15%	5	5

Table 50: Enterprise Data Warehouse Score

The Companies are negotiating with [redacted] to finalize the TMSA and the SOW, which defines the required functionality and deliverables for the EDW Project. The Companies anticipate filing an executed TMSA and SOW by April 2016. If material matters arise in the negotiations that cannot be resolved, the Companies will look to other vendors, including re-evaluating the remaining short list bidders.

III. SINGLE SOURCED VENDORS

As indicated above, SSNI and [redacted] were single-sourced based in part on the Companies' familiarity with the vendors and products they provide.

A. SILVER SPRINGS NETWORKS INC.

The Companies have strategically partnered with SSNI, the market leader in Smart Grid applications and networks. SSNI works with leading utilities that have implemented or are in the process of implementing their Smart Grid to identify, understand and adopt best practices and leverage related industry experience, as well as conducting Smart Grid technology demonstration projects within our service territories to more closely evaluate available technology solutions that will best deliver long-range value for customers.

SSNI was selected based on several factors, which included reviewing potential Smart Grid applications, conferring with peer utilities in various stages of their Smart Grid implementations, experiencing other pilot projects first-hand, and interviewing candidate firms. The benefits of single-sourcing SSNI generally fall into three categories:

1. The partnership provides the fastest path to benefit delivery with the lowest risk for customers. By selecting the network platform first, the Companies were able to quickly deploy a multi-application network and evaluate the technology, accelerate the commencement of a full-scale Smart Grid program, and more accurately quantify cost and benefits. Additionally, by selecting a proven, open network platform upfront, the Companies avoid being locked into a vertically integrated solution, shorten the RFP process for third-party applications by simplifying requirements development and lower project implementation risks.

2. SSNI's technology is scalable, suitable and secure. SSNI's technology is proven with over 22 million connected devices, and the Companies validated the performance first hand during the Initial Phase starting in 2014. The target applications included in this filing are all successfully deployed at-scale with SSNI's network and delivering results with leading U.S. utilities. As discussed in the Companies' Smart Grid roadmap, the Smart Grid will help integrate more Distributed Energy Resources. SSNI's network provides the tools and information needed now, and also supports future grid capabilities that Hawai‘i will need to achieve its clean energy goals. Moreover, SSNI's security is best in class. Both SSNI and the Companies have engaged with third-parties to successfully validate end-to-end network security now and will continue to do this on an on-going basis to ensure customer information is never at risk of compromise.

3. SSNI has provided commercial and partnership commitments to the Companies' Smart Grid initiatives. SSNI has provided guarantees for the contracted pricing of hardware and software, relative to SSNI customers to date of similar size. With respect to partnership commitments, SSNI has also provided support for regulatory requirements, deployment strategy, business case and customer engagement. SSNI has made it a priority to hire local talent, and to support the

initiatives of local energy industry stakeholders including Hawaii Energy, Blue Planet and Energy Excelerator. Further, SSNI has facilitated site visits at other utilities, and enabled the Companies to collect and learn from the best practices of an extensive network of SSNI customers, which will inevitably reduce project risks and expedite delivery of benefits to customers.

The Companies believe a strategic partnership with Silver Spring Networks to be a prudent business decision, one that will help ensure timely customer benefits are delivered efficiently with the lowest risk.

B. [redacted]

Conservation Voltage Reduction (CVR) has several components to enable CVR which include 1) the AMI Meter, 2) the [redacted] and 3) the [redacted] hardware and software. The vendors for the AMI Meter were selected through a competitive bidding process as explained in Section II.B above. The [redacted] is discussed in Section IV.C, below.

The CVR component, [redacted] system, includes hardware and software that was implemented as part of the Initial Phase demonstration project. The Companies purchased a perpetual server-based license and 4,200 meter-based licenses (without seeking recovery) during the Initial Phase and these licenses allow us to utilize the [redacted] system already deployed for expansion as part of the SGF Project. Incremental meter-based licensing costs, priced per meter as additional meters are deployed, will be incurred during the SGF Project. The [redacted] system is proprietary and allows for CVR to be implemented utilizing individual AMI meter voltage data, has demonstrated energy savings from the Initial Phase and has the potential to integrate with smart inverters in the future. The SGF Project leverages the Initial Phase hardware and software installations and provides the fastest option to deploy CVR to certain circuits without requiring much integration work to a central system. The [redacted] and the [redacted] system have been integrated and vetted together in the Initial Phase.

IV. EXISTING VENDORS

As indicated above, [redacted] will be providing products and services pursuant to contracts that were in effect prior to the commencement of selection.

A. [redacted]

The OMS subproject will extend the existing Hawaiian Electric [redacted] OMS, which has been in operation for many years to Maui Electric and Hawaiʻi Electric Light, which do not currently have an OMS. Thus the neighbor islands will be leveraging the investment that Hawaiian Electric has already implemented for their OMS. This approach allows for significant implementation-related cost savings and risk reduction by leveraging the installed system and internal expertise within the enterprise. All integrations for the OMS have already been built during the initial implementation. [redacted] provided the cost data for the OMS figures presented in this Application.

B. [redacted]

Hawaiian Electric, under the existing Residential Direct Load Control (RDLC) program, currently has 32,000 [redacted] pager-based load control switches [redacted] deployed on O'ahu. These [redacted] will trip autonomously upon sensing a line under frequency condition and are also dispatched by System Operation during system emergency situations. During the Initial Phase demonstration project, 160 RDLC [redacted] were replaced with the [redacted] which are integrated with the SSNI mesh network. For the SGF Project, the Companies have chosen to continue utilizing the [redacted] to replace the remaining 31,840 [redacted]

There are only two manufacturers that produce the load control switches compatible with the SSNI mesh network. [redacted] selected because they are [redacted] System Operations continues to have the capability to turn water heaters on and off during system emergency situations. For the installation of the [redacted] Honeywell will be the vendor for the SGF Project. [redacted] was the selected vendor (through a competitive bidding process) to install the original 32,000 [redacted] in 2005 under the RDLC program which was approved by the Commission on October 14, 2004.

[redacted] has been the selected vendor to maintain the existing 32,000 [redacted] to date. The advantages of continuing to utilize [redacted] for the SGF Project include their rapport with the existing 32,000 residential customers, familiarity of the residences and the switch installation, established customer service center for the RDLC program, and maintenance pricing that has only increased approximately 1-2% annually to account for inflation. The cost figures in the accompanying Application were provided by [redacted] and [redacted].

C. [redacted]

The [redacted] was used previously in the Phase 2 East O'ahu Transmission Project with positive results [redacted] In addition, the [redacted] provides cybersecurity for existing systems [redacted] Remote devices and controllers that are installed on the transmission and distribution system, go through an extensive trial and testing period within the Companies to ensure reliable service and therefore the [redacted] as the selected vendor from previous implementations will be used for the CVR deployment as part of the SGF Project. [redacted] and the [redacted] system have been integrated and vetted together in the Initial Phase.

D. [redacted]

The [redacted] Capacitor Bank Control was selected based on its established compatibility, adaptive control capability and proven reliability. The [redacted]

[redacted] has been field tested and found to be compatible with these various manufacturers of capacitor banks. [redacted] controls have been satisfactorily used on [redacted] capacitor bank equipment that existed or exists on the Hawaiian Electric system. The Companies are receiving factory-direct pricing for the Controllers.

[redacted] has recently proposed their new digital capacitor bank control. However, the new [redacted] control is configured to provide numerous control features that are not required for the Companies' specific system applications. The new [redacted] control is currently undergoing technical review to evaluate its technical capability and installation, operational, communication and safety requirements. In addition, the Companies have yet to establish that the Eaton/[redacted] control is compatible with various existing capacitor banks equipment on the system or prove its reliability.

V. CONCLUSION

The general default approach was to select vendors through formal RFP processes. In each case where a SGF Project vendor has been selected outside of the traditional RFP process, the benefit of the selection (i.e., reduced costs to customers and faster development of the Companies' Smart Grid initiatives) has outweighed the need for a formal bidding process.

Exhibit F

Smart Grid Foundation Project

Accounting and Ratemaking Treatment

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LIST OF ATTACHMENTS

Attachment 1 – Accounting for Computer Software

ACCOUNTING AND RATEMAKING TREATMENT

I. SUMMARY

Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Hawai'i Electric Light Company, Inc. ("Hawai'i Electric Light") and Maui Electric Company, Limited ("Maui Electric")[1] propose accounting and ratemaking treatment ("Smart Grid Accounting Treatment") specific to the Smart Grid Foundation Project ("SGF Project").

The SGF Project is a complex project that consists of ten interrelated components consisting of traditional capital expenditures, which include construction and equipment, computer hardware and related software, software development, software services, and the significant interconnection and integration to enable the full benefits of the project. In addition, due to its widespread impact, the SGF Project will require customer outreach and education activities to ensure successful adoption of the project. The SGF project also requires incremental support services from the Project Management Office ("PMO") in order to ensure smooth, cost-effective and coordinated project execution.

The proposed accounting for the interrelated components generally follows the accounting for capital expenditure and software projects approved by the Commission in the past. In general, the cost of equipment and hardware and its related software obtained for the project, such as base hardware, middleware servers, virtual private network ("VPN") infrastructure, tools hardware, imaging hardware and infrastructure changes, will be capitalized. 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 SGF Project 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".[2]

However, because of the interrelated nature of the components, and the transformational nature of the SGF Project, atypical costs will be incurred, and the proposed accounting for each of the specific components is described below.

II. ADVANCED METERING INFRASTRUCTURE

The Advanced Metering Infrastructure ("AMI") component consists of traditional capital expenditure costs, computer hardware, and software development, configuration and implementation.

A. CAPITAL COSTS

The Companies will capitalize the installation costs associated with the new smart meters ("AMI meters") and associated warranty costs (meters are pre-capitalized utility assets) upon

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

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

completion. The installed costs of the meters will include costs that may be necessary to enable the meter socket at the customer site to accept the new AMI meters. In addition, the installed meter costs will include an allocation of the PMO costs and an allocation of the pre-implementation costs that have been included under preliminary engineering designed to mitigate project risks and control costs. Further, the installed meter costs will include the cost of the incremental customer service representatives ("CSRs") that will be contracted to provide call center assistance for expected higher call volumes. The incremental CSRs are an integral part of deploying the AMI meters, and prudent costs that should be recovered;

(1) The Companies propose to depreciate the new AMI meter costs over 20 years, beginning January 1 following the year the meters are capitalized. The 20-year period is proposed, as that is the expected life of these new AMI meters;

(2) The Companies will capitalize the equipment and associated installation cost for the access points ("APs") and relays necessary to extend the range of the meters to be able to communicate with the back office systems. In addition, the installed AP and relay costs will include an allocation of the PMO costs and an allocation of the pre-implementation costs that have been included under preliminary engineering designed to mitigate project risks and control costs. The installed AP and relay cost will be amortized consistent with the Companies' Commission-approved amortization for communication equipment, beginning January 1 following the year the APs and relays are placed in-service;

(3) The Companies will capitalize poles that will be installed and retire the poles that are being replaced to meet pole requirement standards, similar to poles that are currently replaced in the normal course of business. The poles will be included in utility assets upon installation and depreciated based on the Commission-approved depreciation rates for such poles, beginning January 1 following the year the poles are placed in service; and

(4) The Companies will capitalize the hardware for the bandwidth and redundant firewalls of the Companies' data network based on segmentation of the hardware related to AMI provided by Silver Springs Networks, Inc. ("SSNI"). The hardware costs will be amortized consistent with the Companies' Commission-approved amortization for computer equipment.

The capital costs will be recovered through the Renewable Energy Infrastructure Program ("REIP") surcharge ("Surcharge"), as discussed in Exhibit G to the accompanying Application.

B. <u>DEFERRED COSTS</u>

(1) The Companies request to defer the costs for configuration of the AMI software for the AMI meters. The software implementation costs that will be deferred include an allowance for funds used during construction ("AFUDC") during the implementation phase. The deferred software implementation costs will be consistent with ASC 350-40, under which portions of the implementation costs

are deferred and other portions of the software implementation costs (such as end-user training, overhead costs not payroll-related and post implementation costs) are expensed as incurred. As allowed under ASC 350-40, the deferred costs would accrue AFUDC. The deferred software costs will include an allocation of the PMO costs; and

(2) The deferred costs would be amortized over twelve years, beginning the month following the date the software is placed in-service, and the unamortized costs will be included in rate base.

The deferred costs will be recovered through the REIP surcharge, as discussed in Exhibit G to the accompanying Application.

C. EXPENSES

(1) The Companies will expense the firmware maintenance expenses, cybersecurity system tuning, operational support, trouble-shooting, analysis and implementation costs that cannot be deferred (such as end-user training, overhead costs not payroll-related, and post-implementation/stabilization costs), software-as-a-service ("SaaS") fees and the AMI miscellaneous expenses related to cellular services required for communications between the APs and the Companies' back office systems. Expenses related to the AMI component will include an allocation of PMO costs. As discussed in Exhibit G, the expenses for the SGF Project are requested to be recovered through the REIP Surcharge in the year they are budgeted to be incurred. If the Companies' preferred alternative for recovery of expenses for AMI is not approved, these expenses related to the AMI component are requested to be deferred, and would be charged to expense as the costs are recovered through the REIP Surcharge. As discussed in Exhibit G, these deferred costs would be recovered through the REIP Surcharge once the associated component goes live.

D. EXISTING NON-AMI METERS

(1) The Companies will continue to depreciate their existing non-AMI meters over the current Commission-approved depreciation rates and include them as utility assets prior to the meters being replaced. The Companies will also retire the existing non-AMI meters as they are replaced by the new AMI meters; and

(2) The Companies propose to recover the undepreciated cost of their existing meters (i.e., the net book value ("NBV") of the meters when they are replaced with AMI meters) on a straight-line basis over ten years, and to include the unamortized amounts in rate base. Once the Companies' existing non-AMI meters are removed, they will no longer be "used and useful" for utility purposes. The meters were prudently acquired, and the Companies should be able to recover such costs. The revenue requirements ("RR") for the SGF Project include the amortization of the NBV of the meters, over ten years, with the unamortized costs included in rate base.

The net book value of the meters will be recovered through the REIP surcharge, as discussed in Exhibit G to the accompanying Application.

III. CUSTOMER FACING SOLUTIONS

The Customer Facing Solutions ("CFS") component is comprised of software required to provide a pathway for customers to communicate with the utility directly.

A. DEFERRED COSTS

(1) The Companies propose to account for the costs to configure the Smart Utility Systems ("SUS") software and the system integration work of SUS and other systems, including the SAP Customer Information System ("CIS") and the Meter Data Management System ("MDMS"), consistent with 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 labor) are expensed as incurred. As allowed under ASC 350-40, the deferred costs would accrue AFUDC. The deferred software costs will include an allocation of the PMO costs. The deferred cost would include both Information Technology Services ("ITS") and Operations internal employees labor and consultants to perform the development of the software integration and the testing of the application; and

(2) The deferred costs would be amortized over twelve years, beginning the month following the date the software is in-service, and the unamortized costs will be included in rate base.

The deferred costs will be recovered through the REIP surcharge, as discussed in Exhibit G to the accompanying Application.

B. EXPENSES

(1) The Companies will record and recognize the CFS related expenses (e.g., end-user training, support, software maintenance related to the CFS integration work, SaaS fees) and allocated office rental space, and miscellaneous office supplies as incurred. Expenses related to the CFS component will include an allocation of PMO costs. As discussed in Exhibit G, the expenses for the SGF Project are requested to be recovered through the REIP Surcharge in the year they are budgeted to be incurred. If the Companies' preferred alternative for recovery of CFS expenses is not approved, these expenses related to the CFS component are requested to be deferred and would be charged to expense as the costs are recovered through the REIP Surcharge. As discussed in Exhibit G, these deferred costs would be recovered through the REIP Surcharge once the associated component goes live.

IV. CONSERVATION VOLTAGE REDUCTION

The Conservation Voltage Reduction ("CVR") component will include capital costs, deferred costs and expenses.

A. CAPITAL COSTS

(1) The Companies will capitalize the installed costs of the capacitor banks and load tap changer equipment. In addition, the installed capacitor bank costs and load tap changer equipment will include an allocation of the PMO costs and an allocation of the pre-implementation costs that have been included under preliminary engineering designed to mitigate project risks and control costs;

(2) The capacitor banks and load tap changer equipment will be included in plant in-service upon installation, and included in rate base at that time;

(3) The capacitor banks will be included in distribution plant – overhead conductors and devices and the load tap changer equipment will be included in transmission or distribution station equipment assets, and depreciated based on the current Commission-approved rates for such assets, beginning January 1 following the year the capacitor banks and load tap changer equipment are placed in-service;

(4) The Companies will capitalize the costs of the poles that will be installed and retire the poles that are being replaced to meet pole requirement standards, similar to poles that are currently replaced in the normal course of business. The poles will be depreciated based on the Commission-approved depreciation rates for such poles, beginning January 1 following the year the poles are placed in-service; and

(5) The Companies will capitalize the Dominion Voltage Inc. ("DVI") server and SICAMs (additions to the existing SCADA system) required as communication equipment and include costs to integrate the DVI server and SICAMs into respective SCADA systems. The installed DVI server and SICAMs cost will be amortized consistent with the Companies' Commission-approved amortization for communication equipment.

The capital costs will be recovered through the REIP Surcharge as discussed in Exhibit G to the accompanying Application.

B. DEFERRED COSTS

(1) The Companies propose to account for the costs to integrate the DVI server with the TREX, AccuWeather, Enterprise Data Warehouse ("EDW") and Energy Management System ("EMS"), similar to the accounting for software development costs under, ASC 350-40, which allows for specific software implementation costs to be deferred and other portions of the implementation costs (such as end-user training and overheads not related to labor) to be expensed

as incurred. As allowed under ASC 350-40, the deferred costs would accrue AFUDC. The deferred software costs will include an allocation of the PMO costs. The deferred cost will include both ITS and Operations internal employees labor and consultants to perform the development of the software integration and testing of the application.

(2) The deferred costs would be amortized over twelve years, beginning the month following the date the software is in-service, and the unamortized costs will be included in rate base.

The deferred costs will be recovered through the REIP surcharge, as discussed in Exhibit G to the accompanying Application.

C. EXPENSES

The Companies will record and recognize the CVR-related expenses (e.g., end-user training, support, trouble-shooting and analysis, SaaS and software maintenance related to the CVR integration work) and allocated office rental space and miscellaneous office supplies as incurred. Expenses related to the CFS component will include an allocation of PMO costs. As discussed in Exhibit G, the expenses for the SGF Project are requested to be recovered through the REIP Surcharge in the year they are budgeted to be incurred. If the Companies' preferred alternative for recovery of CVR expenses is not approved, these expenses related to the CVR component are requested to be deferred and would be charged to expense as the costs are recovered through the REIP Surcharge. As discussed in Exhibit G, these deferred costs would be recovered through the REIP Surcharge once the associated sub-project goes live.

V. DIRECT LOAD CONTROL

The Direct Load Control ("DLC") component consists of capital costs, deferred costs and expenses.

A. CAPITAL COSTS

(1) The Companies will capitalize the installed costs of the new DLC switches, including warranty costs. In addition, the installed cost of the DLC switches will include an allocation of the PMO costs, and an allocation of the cost to manage and execute the installation of the DLC switches;

(2) The new DLC switches will be included in plant-in-service upon installation, and included in rate base at that time; and

(3) The new DLC switches will be included in communication equipment and amortized over 15 years, beginning January 1 of the year following the installation of the DLC switches, consistent with the Commission-approved amortization period for communication equipment.

The capital costs will be recovered through the REIP Surcharge as discussed in Exhibit G to the accompanying Application.

B. DEFERRED COSTS

(1) The Companies propose to account for the system integration costs related to the DLC switches similar to the accounting for software development costs under 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 labor) are expensed as incurred. As allowed under ASC 350-40, the deferred costs would accrue AFUDC. The deferred software costs will include an allocation of the PMO costs and an allocation of the cost to manage and execute the installation of the DLC switches;

(2) The deferred cost would include both ITS and Operations internal employees labor and consultants to perform the development of the software integration and testing of the application; and

(3) The deferred costs would be amortized over twelve years, beginning the month following the date the software is in-service, and the unamortized costs will be included in rate base.

The deferred costs will be recovered through the REIP surcharge, as discussed in Exhibit G to the accompanying Application.

C. EXPENSES

(1) The Companies will record and recognize the DLC related expenses (e.g., end-user training, support, firmware, maintenance related to the system integration work and SaaS fees) and allocated PMO, office rental space, and miscellaneous office supplies as incurred. Expenses related to the DLC component will include an allocation of PMO costs. As discussed in Exhibit G, the expenses for the SGF Project are requested to be recovered through the REIP Surcharge in the year they are budgeted to be incurred. If the Companies' preferred alternative for recovery of DLC expenses is not approved, these expenses related to the DLC component are requested to be deferred and would be charged to expense as the costs are recovered through the REIP Surcharge. As discussed in Exhibit G, these deferred costs would be recovered through the REIP Surcharge once the associated subproject goes live.

VI. ENTERPRISE DATA WAREHOUSE

The EDW component consists of capital costs, deferred costs and expenses.

A. CAPITAL COSTS

(1) The capital costs for the EDW component relate to computers and phones required for the employees assigned to this component; and

(2) The costs will be included in utility plant when placed in-service, and amortized consistent with the Commission-approved amortization rates for such assets.

The capital costs will be recovered through the REIP Surcharge as discussed in Exhibit G to the accompanying Application.

B. DEFERRED COSTS

(1) The Companies propose to account for the system integration costs related to the EDW similar to the accounting for software development costs under 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 labor) are expensed as incurred. As allowed under ASC 350-40, the deferred costs would accrue AFUDC. The deferred software integration costs will include an allocation of the PMO costs;

(2) The deferred cost will include both ITS and Operations internal employee labor costs and consultants to perform the development of the software integration and testing of the application; and

The deferred costs would be amortized over twelve years, beginning the month following the date the software is in-service, and the unamortized costs will be included in rate base. The deferred costs will be recovered through the REIP surcharge, as discussed in Exhibit G to the accompanying Application.

C. EXPENSES

(1) The Companies will record and recognize the EDW-related expenses (e.g., end-user training, support and maintenance related to the system integration work), internal labor costs to learn and train on the EDW application with the EDW vendor, allocated office rental space and miscellaneous office supplies as incurred. Expenses related to the EDW component will include an allocation of PMO costs. As discussed in Exhibit G, the expenses for the SGF Project are requested to be recovered through the REIP Surcharge in the year they are budgeted to be incurred. If the Companies' preferred alternative for recovery of EDW expenses is not approved, these expenses related to the EDW component are requested to be deferred and would be charged to expense as the costs are recovered through the REIP Surcharge. As discussed in Exhibit G, these deferred costs would be recovered through the REIP Surcharge once the associated component goes live.

VII. ENTERPRISE SERVICE BUS

The Enterprise Service Bus ("ESB") component consists of capital costs, deferred costs and expenses.

A. CAPITAL COSTS

(1) The Companies will capitalize the installation cost for the hardware and related software to extend and enhance the IBM WebSphere ESB. The installed hardware costs will include an allocation of the PMO costs;

(2) The new hardware and its related software will be included in plant-in-service upon installation, and included in rate base at that time; and

(3) The new hardware and its related software will be included in general plant computer equipment and amortized over five years, beginning January 1 of the year following the installation of the hardware, consistent with the Commission-approved amortization period for general plant computer equipment.

The capital costs will be recovered through the REIP Surcharge as discussed in Exhibit G to the accompanying Application.

B. DEFERRED COSTS

(1) The Companies propose to account for the system integration costs related to the ESB similar to the accounting for software development costs under 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 labor) are expensed as incurred. As allowed under ASC 350-40, the deferred costs would accrue AFUDC. The deferred software integration costs will include an allocation of the PMO costs;

(2) The deferred cost will include both ITS and Operations employees labor and consultants to perform the development of the software integration and testing of the application; and

(3) The deferred costs would be amortized over twelve years, beginning the month following the date the software is in-service, and the unamortized costs will be included in rate base.

The deferred costs will be recovered through the REIP surcharge, as discussed in Exhibit G to the accompanying Application.

C. EXPENSES

(1) The Companies will record and recognize the ESB-related expenses (e.g., end-user training, support and maintenance related to the system integration work) and

allocated office rental space and miscellaneous office supplies as incurred. ESB expenses also included the ESB vendor costs to support the application for the five-year rollout of the SGF Project. Expenses related to the ESB component will include an allocation of PMO costs. As discussed in Exhibit G, the expenses for the SGF Project are requested to be recovered through the REIP Surcharge in the year they are budgeted to be incurred. If the Companies' preferred alternative for recovery of ESB expenses is not approved, these expenses related to the ESB component are requested to be deferred and would be charged to expense as the costs are recovered through the REIP Surcharge. As discussed in Exhibit G, these deferred costs would be recovered through the REIP Surcharge once the associated component goes live.

VIII. METER DATA MANAGEMENT SYSTEM

The MDMS component consists of capital costs, deferred costs and expenses.

A. CAPITAL COSTS

(1) The Companies will capitalize the installed MDMS hardware and related software. The installed hardware costs will include an allocation of the PMO costs;

(2) The new hardware and its related software will be included in plant-in-service upon installation and included in rate base at that time; and

(3) The new hardware and its related software will be included in general plant computer equipment and amortized over five years, beginning January 1 of the year following the installation of the hardware, consistent with the Commission-approved amortization period for general plant computer equipment.

The capital costs will be recovered through the REIP Surcharge as discussed in Exhibit G to the accompanying Application.

B. DEFERRED COSTS

(1) The Companies propose to account for MDMS software development costs similar to the accounting for software development costs under 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 labor) are expensed as incurred. As allowed under ASC 350-40, the deferred costs would accrue AFUDC. The deferred MDMS software integration costs will include an allocation of the PMO costs;

(2) The deferred cost will include both internal ITS and Operations employees labor and consultants to perform the development of the software integration and testing of the application; and

(3) The deferred costs would be amortized over twelve years, beginning the month following the date the software is in-service, and the unamortized costs will be included in rate base.

The deferred costs will be recovered through the REIP surcharge, as discussed in Exhibit G to the accompanying Application.

C. EXPENSES

(1) The Companies will record and recognize the MDMS-related expenses (e.g., end-user training, support, and maintenance related to the software development work), office rental space and miscellaneous office supplies as incurred. Expenses related to the MDMS component will include an allocation of PMO costs. As discussed in Exhibit G, the expenses for the SGF Project are requested to be recovered through the REIP Surcharge in the year they are budgeted to be incurred. If the Companies' preferred alternative for recovery of MDMS expenses is not approved, these expenses related to the MDMS component are requested to be deferred and would be charged to expense as the costs are recovered through the REIP Surcharge. As discussed in Exhibit G, these deferred costs would be recovered through the REIP Surcharge once the associated component goes live.

IX. OUTAGE MANAGEMENT SYSTEM

The Outage Management System ("OMS") component consists of capital costs, deferred costs and expenses.

A. CAPITAL COSTS

(1) The capital costs for OMS relate to computers and phones required for the employees assigned to this component,

(2) The costs will be included in utility plant when placed in service, and amortized consistent with the Commission amortization rates for such assets.

The capital costs will be recovered through the REIP Surcharge as discussed in Exhibit G to the accompanying Application.

B. DEFERRED COSTS

(1) The Companies propose to account for the OMS software development and integration costs related to the OMS similar to the accounting for software development costs under 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 labor) are expensed as incurred. As allowed under ASC 350-40, the deferred costs would accrue AFUDC. The deferred software integration costs will include an allocation of the PMO costs;

(2) The deferred cost will include both internal ITS and Operation labor and consultants to perform the development of the software integration and the testing of the application; and

(3) The deferred costs would be amortized over twelve years, beginning the month following the date the software is in-service, and the unamortized costs will be included in rate base.

The deferred costs will be recovered through the REIP surcharge, as discussed in Exhibit G to the accompanying Application.

C. EXPENSES

(1) The Companies will record and recognize the OMS-related expenses (e.g., end-user training, support, maintenance related to the system integration work and SaaS fees), consultant costs for data capture and data cleansing, allocated office rental space, and miscellaneous office supplies as incurred. Expenses related to the OMS component will include an allocation of PMO costs. As discussed in Exhibit G, the expenses for the SGF Project are requested to be recovered through the REIP Surcharge in the year they are budgeted to be incurred. If the Companies' preferred alternative for recovery of OMS expenses is not approved, these expenses related to the OMS component are requested to be deferred. As discussed in Exhibit G, these deferred costs would be recovered through the REIP Surcharge once the associated component goes live.

X. CUSTOMER ENGAGEMENT

The Customer Engagement ("CE") component consists of capital costs and expenses.

A. CAPITAL COSTS

(1) The capital costs for CE relate to computers and phones required for the employees assigned to this component,

(2) The costs will be included in utility plant when placed in service, and amortized consistent with the Commission amortization rates for such assets.

The capital costs will be recovered through the REIP Surcharge as discussed in Exhibit G to the accompanying Application.

B. EXPENSES

(1) The costs incurred for CE activities, including community outreach, customer education, government relations, third party engagement, media relations, customer research, employee engagement and customer service support will be expensed as incurred. The estimated cost for CE activities consists of internal

labor costs, an allocation of PMO costs and miscellaneous costs associated with office equipment and supplies used for CE activities. As discussed in Exhibit G, the expenses for the SGF Project are requested to be recovered through the REIP Surcharge in the year they are budgeted to be incurred. If the Companies' preferred alternative for recovery of CE expenses is not approved, these expenses related to the CE component of the SGF Project are requested to be deferred. As discussed in Exhibit G, these deferred costs would be recovered through the REIP Surcharge, over the respective lives of the AMI assets..

XI. EXISTING ACCOUNTING POLICY FOR SOFTWARE PROJECT COSTS

In Decision and Order No. 18365, filed February 8, 2001 in Docket No. 99-0207 (Hawai'i Electric Light 2000 test year rate case), the Commission ruled that its pre-approval 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' 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. See Attachment 1 for the Companies' existing accounting policy for software project costs.

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

(1) Hardware costs would be capitalized, while software costs would be either expensed or deferred depending on the type of work performed during each stage of the project:

- *Stage 1 – Preliminary Project*: includes conceptual formulation of alternatives, evaluation of alternatives, selection of the new system, and the selection of a consultant to assist in the development/installation of the selected product. These costs are expensed;

- *Stage 2 – Application Development*: includes the design of a chosen path, installation, configuration, testing of software and parallel processing. These costs are generally deferred and amortized.[3] Note, however, that external and internal training costs, as well as certain conversion costs, are expensed; and

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

(2) AFUDC would be applied to the deferred costs during Stage 2;

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

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

(4) Un-amortized deferred costs (including AFUDC) would be included in the calculation of rate base;

(5) Certain overhead costs, other than payroll and payroll-related costs, would be identified, tracked and reclassified to expense on a monthly basis, to the extent these costs are included in the deferred costs; and

(6) In order to properly track the project costs and ensure consistency with the financial accounting policy presented here, the Companies would:

- Establish a project hierarchy to allow for the tracking of project costs based on the project stages as described above; and
- Work with the vendor to ensure sufficient information and activity descriptions are available to support the vendor invoices and to ensure the costs are properly posted and recorded.

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

Attachment 1

Smart Grid Foundation Project

Exhibit F

Accounting for the Costs of Computer Software

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

(Updated as of April 1, 2006)

Introduction

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

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

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

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

Accounting for Computer Software Guidelines

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

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

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

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

  The process of data conversion from old to new systems may include purging or cleansing of existing data, reconciliation or balancing of the old data and the old/new system, creation of new/additional data, and conversion of old data to the new system. Data conversion often occurs during the Application Development Stage; however, data conversion costs, other than the costs to develop or obtain software that allows for access of old data by new systems, should be charged as incurred to the appropriate functional O&M expense account(s), based on the benefiting organization, i.e. expensed as incurred.

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

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

- Preparation of a request for proposal

- Current state assessment – The process of documenting the entity's current business process, except as it relates to current software structure. Often referred to as *mapping, developing an "as-is" baseline, flow charting,* and *determining current business process structure.*

- Process reengineering – The effort to reengineer the entity's business process to increase efficiency and effectiveness. This activity is sometimes referred to as *analysis, determining "best-in-class," profit/performance improvement development,* and *developing "should-be" processes.*

- Restructuring the work force – The effort to determine what employee is necessary.

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

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

(Updated as of April 1, 2006)

Exhibit 1

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

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

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

(Updated as of April 1, 2006)

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

Exhibit G

Smart Grid Foundation Project

Renewable Energy Infrastructure Program Surcharge Recovery

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RENEWABLE ENERGY INFRASTRUCTURE PROGRAM SURCHARGE RECOVERY

I. INTRODUCTION

The Smart Grid Foundation Project ("SGF Project") is complex and unique in terms of its transformational nature, inter-related components, magnitude and duration. The Hawaiian Electric Companies' ("Companies") Renewable Enrgy Infrastructure Program ("REIP") surcharge ("Surcharge") has been specifically tailored to address the cost recovery issues that can arise in connection with these types of complex investments in renewable energy infrastructure. As detailed below, the Companies are proposing certain measures to provide flexibility and tailor the Surcharge in order to further address the unique nature of the costs and timing of the SGF Project.

Among other things, the Companies' Application in this proceeding requests approval to recover revenure requirements associated with the SGF Project-related capital and deferred software development costs (post-in-service/go-live costs, including the remaining book value or the Companies' non-AMI meters), and other relevant costs (including pre-in-service/go-live expenses, post-in-service ongoing expenses and customer engagement expenses), offset by operational benefits that benefit customers by reducing revenue requirements until the Companies' first respective rate case(s) following completion of the SGF Project[1] via:

(1) the REIP Surcharge as described in the *Joint Proposed Modified Renewable Energy Infrastructure Program Framework* ("Modified REIP Framework") filed by the Companies and Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs ("Consumer Advocate") on June 15, 2015 in Docket No. 2013-0141 or, in the alternative;

(2) the REIP Surcharge as approved in the *Decision and Order* filed on December 30, 2009 in Docket No. 2007-0416 ("Existing REIP Surcharge").[2]

As discussed in Section III below, the SGF Project would qualify for cost recovery under both the Modified REIP Framework and the Existing REIP Surcharge. However, the Companies maintain that the Modified REIP Framework is the preferred mechanism for recovery, as the Consumer Advocate and the Companies have agreed and jointly requested the Commission to modify the REIP and the REIP Surcharge according to the Modified REIP Framework in Docket No. 2013-0141. The Modified REIP Framework provides for the surcharge accounting deferrals to be offset by the known and measurable operational net savings or benefits resulting from the SGF Project. Thus, recovering the net costs of the SGF Project (i.e., net of the quantified Operational Benefits) via the Modified REIP Framework would reduce the impact of the surcharge on customer bills.

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[1] The definition and descriptions of the surcharge categories and operational benefits are provided in Section VI.A.

[2] The *Decision and Order* filed on December 30, 2009 in Docket No. 2007-0416 approved the Hawaiian Electric Companies' proposed REIP, including the REIP Surcharge, subject to certain conditions. The Companies provided their proposed REIP in their *Reply Position Statement* filed on September 17, 2008, and the Commission's "Description of the HECO Companies' Proposals" in the *Decision and Order* made repeated reference to the Companies' *Reply Position Statement*. Included as Exhibit B in the *Reply Position Statement* was the *HECO Companies' Proposed Renewable Energy Infrastructure Program Framework* ("Current REIP Framework"), which provided details of the REIP and the REIP Surcharge.

The complexity and scope of the SGF Project make it unlike other projects of smaller scale for which the Companies might apply for recovery through the REIP Surcharge. Thus, the Companies contend that cost recovery for the SGF Project should be approached in a flexible manner, with certain departures from treatment that would otherwise be applied under the provisions of the REIP Surcharge and staggered triennial rate case cycle. For example, a mechanism will need to be created to facilitate surcharge recovery of the substantial SGF Project-related expenses (e.g., pre-in-service/go-live and customer engagement expenses) that will need to be incurred prior to the various subprojects being placed in service. As discussed in Section V below, the Companies are proposing to address this issue by including the budgeted pre-in-service/go-live expenses for each year in the REIP Surcharge in the same year and recovering those expenses over a twelve month period.

The Companies believe it would be unfair and contrary to § 269-16(b)(3), Hawai‘i Revised Statues ("HRS"),[3] for the Operational Benefits of the SGF Project to be passed to customers without allowing the Companies to recover the reasonable costs of achieving those benefits. Moreover, including the pre-in-service/go-live expenses for each year in the REIP Surcharge and contemporaneously recovering those expenses over twelve months would be fair to customers as rates would reflect the cost of the various SGF Project components in the same general timeframe as when the components are providing benefits to customers. If the Commission is not inclined to allow the approach to recovering pre-in-service/go-live and customer engagement expenses proposed above, then the Companies propose in the alternative that the pre-in-service/go-live expense be deferred until their related in-service/go-live dates and included in the REIP Surcharge as part of the first adjustment after the in-service/go-live date.

With respect to the rate case cycle, due to the duration of the SGF Project timeline, it is conceivable that the SGF Project could overlap with one or more of the test years of the Companies' future general rate cases. As discussed in Section VI below, in the interest of simplicity and transparency, the Companies are proposing to address this issue by continuing to include the SGF Project costs and quantified Operational Benefits through the REIP Surcharge until rates take effect in their first respective rate case(s) after the SGF Project has been completed. To ensure against double-counting, the Companies plan to remove project costs and benefits from the revenue requirements of any intervening rate cases. The alternative to this approach would be to incorporate the surcharge amounts into rates during each rate case test year that overlaps the SGF Project schedule, and then re-commence surcharge recovery after such test year(s) until either: (1) the SGF Project is completed; or (2) another rate case test year overlaps with the SGF Project schedule.

It should be noted that because the REIP Surcharge is a volumetric mechanism, recovering the costs of the SGF Project on a cents per kilowatt-hour basis may result in little or no contribution from customers who participate in Net Energy Metering because they are billed on net kWh. The Companies expect to work with the Commission, the Consumer Advocate and other stakeholders in Phase 2 of the Distributed Energy Resources proceeding to address issues of

[3] HRS 269-16(b)(3) requires the Commission to "Do all things that are necessary and in the exercise of the commission's power and jurisdiction, all of which as so ordered, regulated, fixed, and changed are just and reasonable, and provide a fair return on the property of the utility used and useful for public utility purposes."

appropriate recovery for all costs such that the SGF Project costs and benefits are more fairly and reasonably allocated to all customers.[4]

II. REIP SURCHARGE BACKGROUND

In its Decision and Order issued on December 30, 2009, in Docket No. 2007-0416, the Commission approved the Companies' REIP Framework, filed September 17, 2008 as Exhibit B in their *Reply Statement of Position*, subject to certain conditions. Section II.B.1 of the REIP Framework provides that electric utilities may recover the capital costs, deferred costs relating to software development and licenses, and/or other relevant costs approved by the Commission. Section III.B.3.b of the existing REIP Surcharge defined eligible costs to include:

(i) allowed rate of return or other form of return mechanism (set in the last rate case of the utility where the SGF Project is located) on the investment from the in-service date of the SGF Project;

(ii) depreciation (at a rate and methodology to be set forth in the SGF Project's application) to begin the month after the in-service date of the SGF Project;

(iii) AFUDC, applicable taxes, and other capital and deferred expense related charges; and

(iv) other relevant costs as approved by the Commission in an request for approval to include the costs of the SGF Project in the REIP Surcharge.[5]

Pursuant to Order No. 32735, the Companies and the Consumer Advocate submitted the Modified REIP Framework on June 15, 2015, in Docket No. 2013-0141. The Modified REIP Framework is currently pending Commission review and approval.

Section II.A.1 of the Modified REIP Framework provides that, ". . . an electric utility shall be able to seek, through the ratemaking process (i.e., base rates, Revenue Adjustment Mechanism or the REIP Surcharge), recovery of the reasonable and approved capital costs and expenses of Eligible Projects." Pursuant to Section III.C.2.b.iv of the Modified REIP Framework, "Other relevant costs, applicable taxes, and offsetting tax savings" are eligible for cost recovery via the REIP Surcharge.

One of the significant modifications proposed in the Modified REIP Framework is that project cost recovery is netted against project benefits:

> REIP Surcharge accounting deferrals shall be offset by all known and measurable operational net savings or benefits resulting from the Eligible Projects, (including accumulated depreciation and accumulated deferred income tax reserves, reductions in operating and maintenance expenses, related additional revenues, etc.) to the

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[4] The Companies argued that "remedying the (NEM) cost shift on an interim basis should be addressed in Phase 1 and improving overall rate design that affects all customers is more appropriately addressed in Phase 2." Companies' Final Statement of Position filed June 29, 2015, Docket No. 2014-0192, at 73.

[5] Existing REIP Surcharge at 7.

> extent such savings or benefits are not passed 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 would be offset as reasonably realized. 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.[6]

Thus, as shown in Exhibit B § IV, recovering project costs (net of the quantified Operational Benefits) through the Modified REIP Framework instead of the Existing REIP Surcharge would reduce the impact of the SGF Project on customer bills.

III. ELIGIBILITY FOR REIP SURCHARGE RECOVERY

The Modified REIP Framework provides that:

> Projects and costs that may be eligible for inclusion in the Renewable Energy Infrastructure Program include the following examples, subject to the Companies' presenting a sufficient business case, meeting their burden of proof, and obtaining the Commission's approval:
>
> (a) Infrastructure that is necessary to connect renewable energy projects. Infrastructure projects such as transmission lines, interconnection equipment and substations, which are necessary to bring renewable energy to the system. For example, renewable energy projects, such as wind farms, solar farms, biomass plants and hydroelectric plants, not located in proximity to the electric grid must overcome the additional economic barrier of constructing transmission lines, a switching station and other interconnection equipment. Building infrastructure to these projects will encourage additional renewable generation on the grid;
>
> (b) Projects that make it possible to accept more renewable energy. Projects that can assist in the integration of more renewable energy onto the electrical grid. For example, new firm generation or modifications to firm generation to accept more variable renewable generation or energy storage and pumped hydroelectric storage facilities that allow a utility to accept and accommodate more as-available renewable energy;
>
> (c) Projects that encourage clean energy choices and/or customer control to shift or conserve their energy use. Projects that can encourage renewable choices, facilitate conservation and efficient energy use, and/or otherwise allow customers to control their own energy use. For example, smart meters would allow customers to monitor their own consumption and use of electricity and allow for future time-based pricing programs. Systems such as automated appliance switching would provide an incentive to customers

[6] Modified REIP Framework § III.C.3.c.

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 approved preliminary engineering, software development and licenses or special study expensed costs that are found by the Commission to support the deployment of renewable energy or other undertakings of strategic importance to industry transformation, including those transformational projects identified within the Companies' IDRPP, PSIPs or DGIP, as such plans may be approved, modified or accepted by the Commission, and projects consistent with objectives established in investigative dockets, such as the DER docket;

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

(f) Clean Energy Initiative Projects. Projects with the sole purpose of furthering Clean Energy Initiatives, including but not limited to EVs;

(g) Grid Modernization projects. Projects such as smart meters, inverters, energy storage, and distribution automation to enable demand response.[7]

As detailed in Exhibit B and the Companies' *Smart Grid Strategy and Roadmap* ("Smart Grid Roadmap"),[8] one of the primary purposes of the SGF Project is to encourage clean energy choices and/or customer control to shift or conserve their energy use. The SGF Project will also serve as the foundation for additional initiatives that help to connect renewable energy projects, make it possible to accept more renewable energy, support the transformation of the Companies to a utility of the future, further the Companies' clean energy initiatives and modernize the grid. As a result, the SGF Project would qualify for recovery under the Modified REIP Framework.

The Existing REIP Surcharge similarly provides for recovery of:

(i) Infrastructure that is necessary to connect renewable energy projects. . . ;

(ii) Projects that make it possible to accept more renewable energy. . . ; and

(iii) Projects that encourage renewable choices and/or customer control to shift or conserve their energy use. Infrastructure projects and other projects can encourage renewable choices, facilitate conservation and efficient energy use, and/or otherwise allow customers to control their own energy use. For example, there are a variety of projects that could encourage renewable energy choices which include customer selection of renewable resources as well as allowing a customer to use less

[7] Id., § III.B (emphasis in original).
[8] See Exhibit A to the accompanying Application.

> nonrenewable resources. Systems such as 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.[9]

Thus, the SGF Project also qualifies for recovery under the Existing REIP Surcharge.

IV. CONDITIONS FOR MODIFIED REIP FRAMEWORK COST RECOVERY

Sections III.C.3.a through j of the Modified REIP Framework include eleven conditions to qualify a project as eligible for cost recovery via the REIP Surcharge. Each of those conditions are listed in turn below, along with the Companies' explanation/position regarding how each condition is being satisfied:

A. BURDEN OF PROOF

Section III.C.3.a of the Modified REIP Framework provides:

> With respect to applications seeking approval to utilize the REIP Surcharge for cost recovery, the electric utility bears the burden of proof that all project costs proposed for REIP Surcharge 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 that are not Eligible Projects.

As discussed in the Smart Grid Roadmap and further detailed in the SGF Project business case ("Business Case"),[10] Smart Grid is a key component of the Companies' business strategy and ongoing transformation into a modern utility of the future. The SGF Project is a foundational element of the Companies' Smart Grid initiatives. The SGF Project does not involve "routine replacements," "relocations" or "restorations of existing facilities," or other kinds of "business as usual investments."

B. PRUDENCY OF THE INVESTMENT

Section III.C.3.b of the Modified REIP Framework provides:

> REIP Surcharge accounting authority to defer costs for future surcharge recovery, including carrying costs and depreciation deferrals for eligible capital projects, may be granted on an interim basis in the event the Commission has not approved recovery through the REIP Surcharge. If the Commission does not ultimately approve REIP Surcharge recovery and either finds the associated investment to be imprudent and/or ineligible for recovery through any other recovery mechanism or rate case, the deferred costs shall be promptly written off and not resubmitted for

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9 See Existing REIP Surcharge § III.B (emphasis in original).
10 See Exhibit B to the accompanying Application.

recovery in future proceedings. Deferred costs should accrue a carrying charge at the electric utility's short term debt cost rate, applied to the net of deferred income tax deferred investment.

As discussed in the Smart Grid Roadmap and further detailed in the Business Case the Companies maintain that the SGF Project is a prudent, reasonable and necessary investment in furtherance of State energy policy goals.

C. COSTS NET BENEFITS

Section III.C.3.c of the Modified REIP Framework provides:

REIP Surcharge accounting deferrals shall be offset by all known and measurable operational net savings or benefits resulting from the Eligible Projects, (including accumulated depreciation and accumulated deferred income tax reserves, reductions in operating and maintenance expenses, related additional revenues, etc.) to the extent such savings or benefits are not passed 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 would be offset as reasonably realized. 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.

As detailed in Section VI below, the costs for which the Companies are seeking recovery have been netted against the Operational Benefits of the SGF Project that the Companies have been able to reasonably quantify. Specifically, the SGF Project revenue requirements of $272.7 million will be offset by $80.9 million of benefits until the Companies' respective first post-SGF Project rate cases.

D. REIP SURCHARGE ELIGIBILITY

Section III.C.3.d of the Modified REIP Framework provides:

a. Application for Eligible Projects hereunder shall be made, pursuant to General Order 7 procedures. Smaller qualifying capital projects may be combined or grouped into programs to make this showing. Applications shall explain each basis for claimed REIP 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 SGF Project is eligible for surcharge recovery under both the Modified REIP Framework and the Existing REIP Surcharge. Additional discussion of the relationship between the SGF Project and the Companies' overall Smart Grid initiatives is provided in the Smart Grid Roadmap, as well as the Companies' respective Power Supply Improvement Plans.

E. PROJECT BUSINESS CASE

Section III.C.3.e of the Modified REIP Framework 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.

As indicated above, a copy of the SGF Project Business Case is provided as Exhibit B to the accompanying Application.

F. PROJECT SCHEDULE AND BUDGET

Section III.C.3.f of the Modified REIP Framework 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.

As discussed in the Business Case, the SGF Project consists of eight subprojects, a ninth component for customer engagement and a tenth component for project management office ("PMO") services. Section IV of the Business Case includes details on the costs, contingencies, risks and schedules of the subprojects. The anticipated bill impact of the SGF Project is shown in Section VI of the Business Case. Exhibit F to the accompanying Application provides details on the proposed accounting and ratemaking treatment for the SGF Project.

G. CRITERIA FOR USED AND USEFUL STATUS

Section III.C.3.g of the Modified REIP Framework 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.

As detailed in Section IV of the Business Case, each of the SGF Project subprojects has its own schedule and timeframe for "go-live" to provide service to customers. The Companies generally are not seeking to recover the costs of the SGF Project until the periods when the various components are placed into service (i.e., providing service to customers). However, as discussed in Section VI.A below, the Companies are proposing to contemporaneously recover certain preinservice/go-live, customer engagement and PMO expenses in the period they are budgeted to be incurred.

H. POST-IN-SERVICE COSTS

Section III.C.3.h of the Modified REIP Framework provides:

> Recoverable deferred costs, related to the post-in-service period prior to surcharge recovery of Eligible Project investments, shall be limited to the lesser of actual net incurred project/program costs or Commission-approved amounts, net of savings, plus: (i) post-in-service return on investment at the utility's short-term debt cost rate applied to net of income tax investment levels; (ii) deferral of depreciation expenses after in-service, used and useful criteria have been met beginning the next following January 1st and (iii) deferral of qualifying costs otherwise required to be expensed, with carrying charges at the short term debt cost rates applied to net of tax balances. The above carrying costs shall be applied until recovery through the REIP Surcharge or base rates for the applicable costs commences.

Details regarding the Companies' proposed accounting and ratemaking treatment for the post-in-service costs of the SGF Project are provided in Exhibit F.

I. TIMING OF REQUEST

Section III.C.3.i of the Modified REIP Framework provides:

> Complex projects are eligible for recovery through the REIP Surcharge, when supported by detailed business case documentation of reasonably quantifiable expected costs and benefits resulting from such projects. Requests for recovery through the REIP Surcharge should be filed and approved prior to the project going into service (e.g., requests for recovery through the REIP Surcharge can be included in applications filed pursuant to Rule 2.3.g.2 of General Order No. 7 or applications requesting deferral accounting treatment) such that recovery can commence at the effective date of the REIP Surcharge adjustment immediately following the in-service date or completion date of the project.

The SGF Project as described in the Business Case has not commenced and will not commence until the issuance of a decision and order enabling the project to begin. Thus, no elements of the SGF Project have been placed into service.

J. PROCEDURAL STEPS

Section III.C.3.j of the Modified REIP Framework provides:

> Parties to the proceedings on the applications for recovery of costs through the REIP Surcharge shall endeavor to complete procedural steps to allow for approval of the application within seven months of the date of application. The Companies acknowledge that the procedural schedule for complex REIP projects may take longer.

The Companies are committed to completing the procedural steps in the instant docket as quickly as reasonable practicable. At the same time, the Companies acknowledge the complexity of the accompanying Application and recognize that the issuance of a decision and order in this proceeding could take longer than seven months.

V. DURATION OF SURCHARGE

Due to the duration of the SGF Project timeline, it is conceivable that the project could overlap with one or more of the test years of the Companies' future general rate cases. In the interest of simplicity and transparency, the Companies are proposing to address this issue by continuing to include the SGF Project costs and quantified Operational Benefits in the Surcharge until rates take effect in their first respective rate case(s) after the project has been completed. The alternative to this approach would be to incorporate the surcharge amounts into rates during each rate case test year that overlaps the SGF Project schedule, and then re-commence surcharge recovery after such test year(s) until either: (1) the SGF Project is completed; or (2) another rate case test year overlaps with the SGF Project schedule.

A. RATE CASE SCHEDULE

The Companies' current triennial rate case schedule from the start of the SGF Project through to the respective first rate cases after the SGF Project is completed (2017-2024) is provided in Table 1, below.

Company	**Hawaiian Electric**	**Maui Electric**	**Hawai'i Electric Light**	**Hawaiian Electric**	**Maui Electric**	**Hawai'i Electric Light**	**Hawaiian Electric**	**Maui Electric**
Test Year	2017	2018	2019	2020	2021	2022	2023	2024
Project Year	1	2	3	4	5	6	7	8

Table 1

Under this schedule, each of Hawaiian Electric and Maui Electric would have two rate cases during the SGF Project, and Hawai'i Electric Light would have a single rate case in year three of the SGF Project.[11] Under this scenario, the requirement in the Modified REIP Framework that costs recovered through the Surcharge be recovered net of benefits poses certain complications. Incorporating SGF Project costs and benefits into rates in a general rate proceeding while the project is still ongoing gives rise to the question of how those costs and benefits should be treated after the test year has concluded, but additional SGF Project components have not yet been placed into service.

One alternative for addressing this situation would be to normalize the future costs and benefits in the rate proceedings. Although such an approach could potentially be applied to costs and benefits of the operations and maintenance ("O&M") variety, it would be unusual to attempt to normalize the costs and benefits of future capital projects in a rate case. As a result, the

[11] This schedule may not be applicable in a situation where the merger that is pending in Docket No. 2015-0022 were approved (i.e., a "merged" scenario), as the merged scenario assumes a four-year rate case moratorium.

Companies are not proposing this alternative. Instead, the Companies have explored two other options. For purposes of illustration, the Companies are presenting the case of Hawai'i Electric Light, which is scheduled to file a 2019 test year rate case (i.e., year three of the SGF Project) and a 2022 test year rate case (i.e., the first year after the SGF Project is completed). The numbers in the tables shown below are for illustrative purposes only.[12]

B. PURE REIP SURCHARGE OPTION

As illustrated in Table 2 below, the Companies preferred approach for addressing the staggered rate case cycle would be to continue recovery of the SGF Project costs and benefits solely through the REIP Surcharge until the Companies' first respective rate case(s) after the SGF Project has been completed ("Pure Option"). In addition to being simpler than tracking the costs and benefits of the SGF Project across multiple rate case test years during the implementation, it appears that the Pure Option would result in more accurate and transparent tracking of SGF Project costs and benefits.

[12] In the merged scenario, it is assumed that the first rate case filing will occur as a consolidated, tri-company filing in 2021. In that event, consideration will need to be given as to when and how the balances included in the REIP Surcharge should be reflected in base rates. For purposes of comparison, both the unmerged and merged scenarios utilize the same REIP Surcharge assumptions.

Pure Option - Recovery of Hawai‘i Electric Light Project Costs Through REIP Surcharge Until First Post-Go-Live Rate Case (Illustrative)							
	Year	**2017**	**2018**	**2019 Rate Case**	**2020**	**2021**	**2022 Rate Case**
Cost Expense from Year	2017	2	2	2	2	2	2
	2018	0	3	3	3	3	3
	2019	0	0	2	2	2	2
	2020	0	0	0	1	1	1
	2021	0	0	0	0	1	1
	2022	0	0	0	0	0	1
	Total Cost by Year	**2**	**5**	**7**	**8**	**9**	**10**
Benefit Expense from Year	2017	-1	-1	-1	-1	-1	-1
	2018	0	-3	-3	-3	-3	-3
	2019	0	0	-4	-4	-4	-4
	2020	0	0	0	-2	-2	-2
	2021	0	0	0	0	-1	-1
	2022	0	0	0	0	0	-2
	Total Benefit by Year	**-1**	**-4**	**-8**	**-10**	**-11**	**-13**
Net Cost/Benefit		**1**	**1**	**-1**	**-2**	**-2**	**-3**
Mechanism	**REIP Surcharge**	**1**	**1**	**-1**	**-2**	**-2**	**0**
	Base Rates	**0**	**0**	**0**	**0**	**0**	**-3**
Net REIP/Base Rates		**1**	**1**	**-1**	**-2**	**-2**	**-3**

Note: 1. For simplification purposes, this illustration does not include return on rate base impacts.

Table 2

C. HYBRID RATE CASE AND SURCHARGE OPTION

As illustrated in Table 3 below, a second and more complicated option ("Hybrid Option") would be for Hawai‘i Electric Light to commence recovery of net SGF Project costs through the REIP Surcharge (to the extent placed in service) in 2017. In Hawai‘i Electric Light's 2019 test year rate case, the 2019 costs and benefits to date would be reflected in that company's test year revenue requirements.[13] In 2020, SGF Project costs and future benefits would once again need to be included in the Surcharge. A potential solution would be that once rates take effect in the 2019 test year rate case, the costs and Operational Benefits previously included in the Surcharge for 2017-2019 would be removed from the surcharge, with the 2019 and 2020 costs and Operational Benefits that are not included in the 2019 test year revenue requirements then being included in the Surcharge.

[13] The actual estimated revenue requirements of the SGF Project are provided in Section VII below.

Hybrid Option - Recovery of Hawai'i Electric Light Project Costs Through REIP Surcharge and Rate Case Revenue Requirement (Illustrative)							
	Year	**2017**	**2018**	**2019 Rate Case**	**2020**	**2021**	**2022 Rate Case**
Cost Expense from Year	2017	2	2	2	2	2	2
	2018	0	3	3	3	3	3
	2019	0	0	2	2	2	2
	2020	0	0	0	1	1	1
	2021	0	0	0	0	1	1
	2022	0	0	0	0	0	1
	Total Cost by Year	**2**	**5**	**7**	**8**	**9**	**10**
Benefit Expense from Year	2017	-1	-1	-1	-1	-1	-1
	2018	0	-3	-3	-3	-3	-3
	2019	0	0	-4	-4	-4	-4
	2020	0	0	0	-2	-2	-2
	2021	0	0	0	0	-1	-1
	2022	0	0	0	0	0	-2
	Total Benefit by Year	**-1**	**-4**	**-8**	**-10**	**-11**	**-13**
Net Cost/Benefit		**1**	**1**	**-1**	**-2**	**-2**	**-3**
Mechanism	**REIP Surcharge**	**1**	**1**	**0**	**-1**	**-1**	**0**
	Base Rates	**0**	**0**	**-1**	**-1**	**-1**	**-3**
Net REIP/Base Rates		**1**	**1**	**-1**	**-2**	**-2**	**-3**

Note: 1. For simplification purposes, this illustration does not include return on rate base impacts.

Table 3

Although the Pure Option appears simpler than the Hybrid Option, it still would present difficulties that would need to be addressed. The Companies would need to make adjustments in the rate case test year revenue requirements to reverse out the reflection of all SGF Project benefits and costs to avoid the double counting of benefits and costs in both the rate case revenue requirements (i.e., base rates) and the REIP Surcharge. For example, returning to the case of Hawai'i Electric Light, if the net costs included in the REIP Surcharge in 2019 were to reflect the benefit of a reduction in the number of that company's meter readers, then in order to avoid double-counting the benefit of that reduction in O&M expense, Hawai'i Electric Lights's 2019 test year revenue requirements would need to reflect an upward adjustment related to the meter reader positions that have been eliminated.

Notwithstanding the difficulties presented by either option, the Companies maintain that the Pure Option would be more workable and desirable than the Hybrid Option. Although technically different, the net revenue requirements assigned to customers would be the same under either option. Regardless of the approach taken, either approach will require some degree of flexibility in implementation, in order to address any additional issues that may arise. The

Companies are open to working with the Commission and Consumer Advocate to formulate a mutually agreeable approach/process for applying the REIP Surcharge to the SGF Project.

VI. SGF PROJECT REIP SURCHARGE DETAILS

A. SURCHARGE CATEGORIES

The items the Companies are proposing to include in the REIP Surcharge pursuant to the Modified REIP Framework generally fall into five categories: (1) post-in-service/go-live costs (i.e., depreciation/amortization of and return[14] on capital, deferred software development costs and other "recoverable deferred costs" ("Post-In-Service/Go-Live Costs");[15] (2) relevant pre-in-service/go-live expenses ("Pre-In-Service/Go-Live Expenses"); (3) relevant post-in-service/go-live ongoing expenses ("Post-In-Service/Go-Live Ongoing Expenses"); (4) relevant customer engagement expenses ("Customer Engagement Expenses"); and (5) quantified monetary operational savings ("Operational Benefits"). The Companies will also implement a true-up mechanism that will reconcile actual revenue recovered through the surcharge with the approved revenue requirements to be recovered during the subject year, and return/recover the balance through the surcharge in a subsequent period.[16] Due to differences in timing and existing accounting rules for these various surcharge categories, the inclusion of each various category in the REIP Surcharge is discussed in a separate respective section below.[17]

1. Post-In-Service/Go-Live Costs

Prior to the Companies' first post-in-service/go-live rate cases, the revenue requirement associated with the SGF Project capital and deferred software development costs will be recovered through the Modified REIP Framework. The Companies will capitalize and defer software-related costs according to existing accounting practices. Table 4, below, provides a breakdown of the SGF Project Post-In-Service/Go-Live Costs. As the Modified REIP Framework provides, the REIP Surcharge would recover the return at the AFUDC rate on the net plant in-service and unamortized balance of deferred costs for the SGF Project; recorded depreciation expense, which will begin January 1st following each respective in-service date; and amortization of any recorded regulatory asset balances, related to deferred software development costs and other "recoverable

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[14] Modified REIP Framework § III.C.2.b.(i) prescribes return on capital and deferred costs to be at the "AFUDC rate," which Section I of the Modified REIP Framework defines as "the rate applied to construction work in progress to calculate the Allowance for Funds Used During Construction. The rate calculated annually (reviewed quarterly and adjusted as necessary) is the weighted average cost of capital, reflecting the projected capital structure for the year. The cost of debt, preferred stock, and hybrid securities uses the embedded costs and anticipated issuance of new securities and retirements of existing securities. The cost of common equity is based on the rate authorized by the Commission in the most recent rate case for the applicable electric company."

[15] See id., § III.C.3.h.

[16] See id., § III.C.4.e.

[17] The Companies' general approach to recovering the costs of the SGF Project via the Modified REIP Framework would be the same under an "unmerged" scenario as under the merged scenario described above. One material difference between recovery under the unmerged and merged scenarios relates to the timing of the costs and benefits, which would be accelerated under the merged scenario. A second difference relates to the timing of the Companies' rate cases which are assumed to follow the staggered triennial rate case cycle under the unmerged scenario, but may be modified following a four-year rate case moratorium under the merged scenario. The subsections below discuss how the REIP Surcharge could operate under both the unmerged and merged scenarios.

deferred costs,"[18] which will begin on the first day of the month after each respective go-live date.[19] Between the in-service/go-live date and the commencement of REIP Surcharge recovery, a post-in-service return on investment will be applied to the undepreciated/unamortized amounts at the Companies' short-term debt rates.

Unmerged Consolidated SGF Project Post-In-Service/Go-Live Costs (Nominal $000s)			
	Capital	Deferred	Total
Hawaiian Electric	95,995	59,688	155,683
Hawai'i Electric Light	21,168	3,044	24,212
Maui Electric	28,387	5,168	33,555
Total	**145,550**	**67,900**	**213,450**

**assumes to show till first rate cases by company for unmerged

Table 4

Table 5, Table 6 and Table 7 below provide the revenue requirements for the Post-In-Service/Go-Live Costs by utility and year for the unmerged scenario.

Unmerged Hawaiian Electric SGF Project Post-In-Service/Go-Live Costs (Nominal $000s)							
	2017	2018	2019	2020	2021	2022	Total
Capital	2,736	12,063	17,789	19,792	21,764	21,851	95,995
Deferred	1,243	6,376	12,026	13,623	13,456	12,964	59,688
Total	**3,979**	**18,439**	**29,815**	**33,415**	**35,220**	**34,815**	**155,683**

Table 5

Unmerged Hawai'i Electric Light SGF Project Post-In-Service/Go-Live Costs (Nominal $000s)						
	2017	2018	2019	2020	2021	Total
Capital	78	1,136	4,472	7,597	7,885	21,168
Deferred	-	16	815	1,130	1,083	3,044
Total	**78**	**1,152**	**5,287**	**8,727**	**8,968**	**24,212**

Table 6

[18] See id., § III.C.3.h.
[19] See id., § III.C.2.b.iii. For a schedule of the associated life of each asset, see also Attachment 6 of Exhibit B to the accompanying Application.

Unmerged Maui Electric SGF Project Post-In-Service/Go-Live Costs (Nominal $000s)								
	2017	2018	2019	2020	2021	2022	2023	Total
Capital	78	892	3,411	5,881	6,107	6,128	5,890	28,387
Deferred	-	15	810	1,124	1,078	1,031	1,110	5,168
Total	**78**	**907**	**4,221**	**7,005**	**7,185**	**7,159**	**7,000**	**33,555**

Table 7

2. Pre-In-Service/Go-Live Expenses

Under existing accounting treatment, certain pre-in-service/go-live software implementation costs relevant to the SGF Project are expensed. Specifically, the Companies' accounting policy for the costs of computer software developed or obtained for internal use states that the costs for: (1) data migration regarding converting data from old to new systems, reconciliation and balancing of old data and the new data in the new system, creation of additional data and conversion of the old data to the new system; (2) software maintenance/software-as-a-service ("SaaS") fees; and (3) training (i.e., end-user trainer), for the SGF Project will be expensed. Additionally, there are also miscellaneous costs related to the personnel who are performing the work stated above.

The total SGF Project Pre-In-Service/Go-Live Expenses are estimated at approximately $23.4 million, and consists of costs for internal labor, maintenance, miscellaneous and outside services cost categories as described in Section II.A.2 of the Business Case and summarized in Table 8 below.

Total Unmerged SGF Project Pre-In-Service/Go-Live Expenses by Project Component and Cost Category (Nominal $000s)					
Component	Internal Labor	Maintenance	Misc.	Outside Services	Total
AMI	375	4,342	190	3,297	8,204
CFS	236	835	28	91	1,190
CVR	98	3,195	75	40	3,408
DLC	26	855	35	11	927
MDMS	520	2,873	365	202	3,960
OMS	295	1,007	112	4,310	5,724
Total	**1,550**	**13,106**	**805**	**7,952**	**23,413**
Note: PMO costs are allocated to individual components.					

Table 8

By far the largest portion of the expenses above are for AMI subproject Maintenance (mainly for the SaaS fees – approximately $4.3 million) and Outside Services (mainly for cybersecurity monitoring and cellular services – approximately $3.5 million) as described in Section II.B.1 of the Business Case. Aside from the AMI subproject activities, the bulk of the remaining Pre-In-Service/Go-Live Expenses are for related software maintenance, training and project management for the CFS, CVR, DLC, MDMS and OMS subprojects (approximately $9.5 million). Another significant portion of the expenses is for OMS subproject outside services to conduct data migration and conversion of existing data to the new system, reconciliation and balancing of such data between systems and creation of additional data needed by the new system (approximately $4.2 million). See Attachment 1 for additional details.

The SGF Project will be one of the largest and most complex projects that the Companies have ever undertaken. As detailed in the Business Case, the total costs of the SGF Project is approximately $340 million. Within that cost estimate are approximately $23.4 million of Pre-In-Service/Go-Live Expenses for which there is currently no mechanism for recovery other than a general rate case,[20] and which the Companies would not otherwise incur but for the need to transform the way the Companies do business and to provide the benefits of Smart Grid technologies to customers. Requiring the Companies to absorb $23.4 million of expenses with no means for cost recovery could undermine the Companies' financial integrity and would be contrary to providing the Companies with a reasonable opportunity to earn a fair return on their utility property.[21] As explained above, the Companies recommend continuing to include the SGF Project costs and quantified Operational Benefits in the REIP surcharge until rates take effect in their first respective rate case(s) after the SGF Project has been completed. Recovering Pre-In-Service/Go-Live Expenses in the REIP Surcharge would be consistent with that approach and would be more straightforward and transparent than normalizing such expenses in intervening and staggered rate case test years for the three Companies.[22]

For purposes of cost recovery via the Modified REIP Framework, the Companies are proposing two general approaches. The Companies' preferred approach is to flow these expenses through the REIP Surcharge in the year that they are budgeted to be incurred. The second alternative is to defer these costs and recover the deferred amounts and relevant carrying charges through the REIP Surcharge once the associated subproject goes live.

The total costs of these Pre-In-Service/Go-Live Expenses over the anticipated five-year life of the SGF Project are shown in Table 9, below.

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[20] Assuming continuation of the Companies staggered three-year rate case cycle and the ability to normalize these expenses between rate cases, the impact of not being able to recover these Pre-In-Service/Go-Live Expenses through rate cases would be $0 for Hawaiian Electric (since Hawaiian Electric would have a 2017 test year rate case), $1.2 million for Maui Electric (which would have a 2018 test year rate case), and $2.9 million for Hawaiʻi Electric Light (which would have a 2019 test year rate case). Assuming a four-year rate case moratorium from 2017 through 2020 and rate cases in 2021, the impact of not being able to recover these expenses through rate cases would be $14.5 million for Hawaiian Electric, $3.7 million for Maui Electric and $4.1 million for Hawaiʻi Electric Light.

[21] See HRS § 269-16(b)(3).

[22] In addition, it is uncertain as of the date of the accompanying Application exactly when each company will file its next rate case that will be fully processed to a final decision and order on the company's test year revenue requirements.

Unmerged SGF Project Pre-In-Service/Go-Live Expenses by Year (Nominal $000s)						
	2017	2018	2019	2020	2021	Total
Hawaiian Electric	7,090	3,514	3,075	847	755	15,280
Hawai‘i Electric Light	1,223	1,654	967	201	198	4,243
Maui Electric	1,223	1,513	833	162	160	3,890
Total	**9,535**	**6,681**	**4,875**	**1,210**	**1,112**	**23,413**

Table 9

Under the Companies' preferred approach, the budgeted Pre-In-Service/Go-Live Expenses for each year of the SGF Project will be included in the REIP Surcharge and recovered over twelve months. Following each year of the SGF Project, the Pre-In-Service/Go-Live Expenses included in the Surcharge for that year will be trued up to adjust for the difference between the amount budgeted versus the amount actually incurred (as well as any over/under recovery resulting from the difference between forecast sales and actual sales). This true-up will occur in the first quarter after each respective year of the SGF Project. Although this approach would allow these costs to be recovered through the REIP Surcharge prior to the in-service date of the associated project component, it would result in these costs being expensed, consistent with the Companies' software accounting policy.

If the Commission is not inclined to allow the Companies to recover the Pre-In-Service/Go-Live Expenses through the REIP Surcharge in the above manner, one alternative would be to defer the Pre-In-Service/Go-Live Expenses until their related in-service/go-live dates and include and recover them in their entirety through the REIP Surcharge as part of the first adjustment after the in-service/go-live date. A second alternative would be to defer the Pre-In-Service/Go-Live Expenses until their related in-service/go-live dates and include and recover them over the respective lives of the related assets.

Allowing the Companies to defer the Pre-In-Service/Go-Live Expenses of the SGF Project would be consistent with the Modified REIP Framework,[23] and in line with long-standing principles that have been recognized by the Commission. For example, in Order No. 30229 ("Order 30229"), filed February 24, 2012 in Docket No. 2010-0080 (Hawaiian Electric 2011 test year rate case), the Commission discussed the "exceptional cases" in which deferral accounting treatment should be granted. One of those cases pertains to circumstances that meet the "beyond control/magnitude" standard set forth in In re Citizens Util. Co., Kauai Elec. Div., Docket No. 94-0045, Decision and Order No. 13572 (1994). The Commission also acknowldeged –

> – some action taken to advance defined State policy directives, such as the Hawai‘i Clean Energy Initiative ("HCEI"), require atypical but prudent expenditures that

[23] See, e.g., Modified REIP Framework § III.C.2.b.(iii), which specifies the "amortization of any recorded regulatory asset balances, over a Commission approved period, and any other capital and deferred expense related charges" to be costs eligible for the REIP Surcharge.

> HECO may otherwise not undertake. Thus, in addition to the beyond control/magnitude requirement stated previously, expenditures associated with advancing the State's defined energy policies may be eligible for deferred accounting treatment. However, deferred accounting treatment is not automatic, and any request must be submitted to the commission for approval on a case by case basis.[24]

In a footnote, the Commission added, "Arguably, expenditures related to State policy directives like HCEI Agreement would fall under the beyond control/magnitude standard as well."[25]

The SGF Project is an exceptional case warranting cost deferral. Smart Grid is a key component of State energy policy and the Companies' transformation to a modern utility of the future. The *Commission's Inclinations* specifically identify Smart Grid as one of the key components for developing a state-of-the-art distribution system to enable clean energy in Hawaiʻi and discuss how advance metering technologies will serve as the key foundational infrastructure for an advanced distribution system.[26] Thus, the Companies maintain that the SGF Project meets the Commission's beyond control, magnitude and State energy policy standards for cost deferral.

3. Post-In-Service/Go-Live Ongoing Expenses

The Post-In-Service/Go-Live On-going Expenses contain: (1) stabilization costs associated with the assets implemented in the SGF Project ("Stabilization Costs"); and (2) post-in-service/go-live ongoing operational support, maintenance and lifecycle management expenses ("Ongoing Costs") as detailed in Attachment 2. Stabilization Costs include efforts to finalize and transition support of the new systems/assets to regular operations, work to address any remaining open issues from the in-service/go-live event, as well as project management close out activities. The Companies' accounting policy requires that certain post implementation / operation stage activities (including relevant costs for incremental internal labor) for the SGF Project be expensed. This includes costs for training end-users within the Companies, software maintenance/SaaS fees and ongoing support (e.g., lifecycle management, troubleshooting, preventative maintenance, analysis). The total costs for these Post-In-Service/Go-Live Ongoing Expenses until the anticipated timing of the Companies' respective first post-SGF Project rate cases are shown (in order of their respective first rate case test years) in Table 10 below. The ongoing expenses go to zero in the year of the first post-SGF Project rate case since those expenses will be removed from the REIP Surcharge and included in the rate case test year revenue requirements.

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[24] Order 30229 at 18-19 (footnotes omitted).
[25] Id. at 19, n.36.
[26] *Appendix A: Commission's Inclinations on the Future of Hawaii's Electric Utilities* to Decision and Order No. 32052, filed April 28, 2014 in Docket No. 2012-0036 is referred to as the "Commision's Inclinations". See id. at 14-15.

Unmerged SGF Project Post-In-Service Ongoing Expenses by Utility and Year (Nominal $000s)									
Company	2017	2018	2019	2020	2021	2022	2023	2024	Total
Hawaiian Electric	-	501	1,353	4,428	5,462	14,457	-	-	26,200
Hawai‘i Electric Light	-	-	150	885	905	-	-	-	1,939
Maui Electric	-	-	124	737	754	2,346	1,912	-	5,873
Total	**-**	**501**	**1,627**	**6,050**	**7,120**	**16,803**	**1,912**	**-**	**34,012**

**assumes to show till first rate cases by company for unmerged

Table 10

Similar to the Pre-In-Service/Go-Live Expenses, the budgeted Post-In-Service/Go-Live Ongoing Expenses for each year after a SGF Project component is placed in-service or goes live will be included in the REIP Surcharge in the same year and recovered over twelve months. This process would continue until each Companies' first respective post-SGF Project rate case when the applicable ongoing expenses would be included in the test year revenue requirement. The Post-In-Service/Go-Live Ongoing Expenses that are included in the surcharge will be trued up in the same manner as the Pre-In-Service/Go-Live Expenses.

4. Customer Engagement Expenses

As discussed in Exhibit C to the accompanying Application, in order to be successful, the SGF Project will require a proactive, targeted, collaborative and responsive dialog to educate and engage with customers, thereby encouraging customers to take maximum advantage of the new technologies and options enabled by the SGF Project. These activities will be carried out upon commencement of the SGF Project and continue until the project is completed. One of the challenges with fitting these costs into the REIP Surcharge is that there is no discrete customer engagement "asset" place in-service/go-live, but it supports the entire SGF Project.

In order to address this issue, as shown in Table 11 below, the Companies are proposing to treat the Customer Engagement Expenses similar to the Pre-In-Service/Go-Live Expenses, with the budgeted Customer Engagement Expenses for each respective year being included in the REIP Surcharge in the same year and recovered over twelve months. This process would continue until each Companies' first respective post-SGF Project rate case, when the Customer Engagement Expenses, if any, would be included in the test year revenue requirement. The Customer Engagement Expenses that are included in the REIP Surcharge will be trued up in the same manner as the other expenses above.

Unmerged SGF Project Customer Engagement Expenses by Year (Nominal $000s)									
	2017	2018	2019	2020	2021	2022	2023	2024	Total
Hawaiian Electric	2,619	1,327	1,201	891	629	-	-	-	6,668
Hawai'i Electric Light	-	284	257	191	135	-	-	-	868
Maui Electric	-	284	257	191	135	-	-	-	868
Total	**2,619**	**1,896**	**1,716**	**1,273**	**899**	**-**	**-**	**-**	**8,403**

Table 11

If the Commission is not inclined to allow the Companies to recover the Customer Engagement Expenses through the REIP Surcharge in the above manner, one alternative would be to defer the Customer Engagement Expenses until their related AMI implementation in-service/go-live dates and include and recover them in their entirety through the REIP Surcharge as part of the first adjustment after the in-service/go-live date. A second alternative would be to defer the Customer Engagement Expenses until their related AMI implementation in-service/go-live dates and include and recover them over the respective lives of the related AMI assets.

5. Operational Benefits

As indicated above, Section III.C.3.c of the Modified REIP Framework requires that cost recovery under the surcharge be offset by all Operational Benefits resulting from the SGF Project. As shown in Table 12, below.

Similar to the relevant expenses of the SGF Project, the Companies are proposing to include these Operational Benefits for each year in the REIP Surcharge in the same year they are realized and credit customers for those benefits over the course of twelve months.[27] Additionally, as shown in below, these benefits will flow through the REIP Surcharge until each company's respective first rate cases after the SGF Project is completed.

Consolidated SGF Project Operational Benefits by Type and Year (Nominal $000s)									
	2017	2018	2019	2020	2021	2022	2023	2024	Total
Capital	1,702	2,084	2,400	2,517	2,584	2,159	390	-	13,836
Expense	1,757	5,348	9,679	12,368	12,447	9,413	1,695	-	52,707
Total	**3,459**	**7,432**	**12,079**	**14,885**	**15,031**	**11,572**	**2,085**	**-**	**66,543**

Table 12

Table 13, Table 14 and Table 15 below summarize the Operational Benefits specific to Hawaiian Electric, Hawai'i Electric Light and Maui Electric, respectively.

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[27] Details regarding the Operational Benefits of the SGF Project are provided in Section III of Exhibit B to the accompanying Application.

Hawaiian Electric SGF Project Operational Benefits by Type and Year (Nominal $000s)									
	2017	2018	2019	2020	2021	2022	2023	2024	Total
Capital	1,417	1,713	1,815	1,739	1,754	1,777	-	-	10,215
Expense	1,462	4,396	7,321	8,543	8,451	7,747	-	-	37,920
Total	**2,880**	**6,109**	**9,136**	**10,282**	**10,206**	**9,524**	**-**	**-**	**48,137**

Table 13

Hawai‘i Electric Light SGF Project Operational Benefits by Type and Year (Nominal $000s)									
	2017	2018	2019	2020	2021	2022	2023	2024	Total
Capital	134	160	270	398	460	-	-	-	1,422
Expense	139	410	1,087	1,958	2,216	-	-	-	5,810
Total	**273**	**570**	**1,357**	**2,356**	**2,676**	**-**	**-**	**-**	**7,232**

Table 14

Maui Electric SGF Project Operational Benefits by Type and Year (Nominal $000s)									
	2017	2018	2019	2020	2021	2022	2023	2024	Total
Capital	151	211	315	380	370	382	390	-	2,199
Expense	156	542	1,271	1,867	1,780	1,666	1,695	-	8,977
Total	**308**	**753**	**1,587**	**2,247**	**2,150**	**2,048**	**2,085**	**-**	**11,178**

Table 15

Although the inclusion of budgeted expenses and benefits in the Surcharge on a yearly basis will result in some expenses and benefits being included slightly before they are incurred or realized, the Companies believe this approach is reasonable under the circumstances, as it will be simpler to track, and will speed up the inclusion of benefits relative to the inclusion of costs (since only some of the expenses, i.e., just the pre/post in-service/go-live expenses, will be included before they are incurred).

B. OVERALL SGF PROJECT SURCHARGE

The net impact of including the: (1) Post-In-Service/Go-Live Costs; (2) Pre-In-Service/Go-Live Expenses; (3) Post-In-Service/Go-Live Ongoing Expenses; and (4) Operational Benefits, of the SGF Project in the REIP Surcharge is shown in Table 16, below.

Unmerged SGF Project Estimated REIP Cost Recovery Surcharge (Monthly $ Per Customer)								
Company	2017	2018	2019	2020	2021	2022	2023	2024
Hawaiian Electric	1.16	1.81	2.49	2.67	2.88	3.14	-	-
Hawai‘i Electric Light	0.63	1.57	3.21	4.43	4.30	-	-	-
Maui Electric	0.56	1.17	2.23	3.14	3.17	3.34	3.00	-

Table 16

As shown in Table 16 above, the REIP Surcharge for the SGF Project (based on typical residential monthly usage of 500 kWh and the sales forecasts assumed in the Companies' February 2016 Power Supply Improvement Plans) will peak in 2018 and decrease through 2021, after which time the relevant costs and benefits of the project will be moved into the revenue requirements used to set each Companies' future base rates. Table 17, below provides the estimated Surcharge expected in the merged scenario, which was developed by applying the Operational Benefits against the merged scenario costs presented in Exhibit I.

Merged SGF Project Estimated REIP Cost Recovery Surcharge (Monthly $ Per Customer)					
Company	2017	2018	2019	2020	2021
Hawaiian Electric	1.47	2.26	2.47	2.37	-
Hawai‘i Electric Light	0.76	1.67	3.42	4.47	-
Maui Electric	0.69	1.44	2.71	3.20	-

Table 17

C. REVENUE REQUIREMENTS

1. Umerged Scenario

As indicated above, the Companies have performed a present value of revenue requirements ("PVRR") analysis (as distinguished from the broader economic analysis provided in the SGF Project Business Case-see Exhibit B to the accompanying Application) to understand the impact of the SGF Project on revenue requirements over the life of the investment. The PVRR analysis excludes direct customer benefits which would not flow through the Companies' revenue requirements.

In an Unmerged Scenario, the SGF Project is expected to nominally cost $518 million, $97 million, and $112 million in revenue requirements over the 2017-2036 timeframe at Hawaiian Electric, Maui Electric, and Hawai‘i Electric Light respectively. See detailed information in Table 18, below:

Unmerged SGF Project Cost to Customers (Present Value $000s)				
Year	**Hawaiian Electric**	**Maui Electric**	**Hawai‘i Electric Light**	**Consolidated**
2017	15,079	1,242	1,263	17,584
2018	23,899	2,656	3,161	29,716
2019	33,261	5,118	6,508	44,887
2020	35,512	7,268	9,054	51,834
2021	37,949	7,354	8,818	54,121
2022	40,959	7,778	9,083	57,820
2023	36,042	7,053	8,351	51,446
2024	34,504	6,780	7,963	49,247
2025	34,327	6,434	7,458	48,219
2026	31,176	6,163	7,106	44,445
2027	31,864	6,033	6,895	44,792
2028	28,058	5,884	6,848	40,790
2029	26,211	5,331	6,103	37,645
2030	20,401	4,118	4,561	29,081
2031	17,262	3,477	3,831	24,570
2032	16,542	3,282	3,540	23,363
2033	15,247	3,070	3,216	21,533
2034	13,188	2,795	2,757	18,739
2035	13,608	2,680	2,545	18,833
2036	13,314	2,550	2,460	18,324
Nominal Value	**$518,403**	**$97,066**	**$111,519**	**$726,989**
Present Value	**$273,549**	**$49,353**	**$57,699**	**$380,601**

Table 18

2. <u>Merged Scenario</u>

In the merged scenario, the SGF Project is expected to nominally cost $467 million, $99 million, and $109 million in revenue requirements over the 2017-2036 timeframe at Hawaiian Electric, Maui Electric, and Hawai‘i Electric Light respectively. <u>See</u> detailed information in Table 19, below:

Merged SGF Project Cost to Customers (Present Value $000s)				
Year	**Hawaiian Electric**	**Maui Electric**	**Hawai'i Electric Light**	**Consolidated**
2016	1,266	4	4	1,274
2017	19,118	1,548	1,520	22,186
2018	29,870	3,267	3,362	36,500
2019	32,987	6,222	6,937	46,146
2020	31,453	7,392	9,147	47,992
2021	33,379	7,099	8,422	48,900
2022	35,602	7,602	8,751	51,955
2023	31,208	6,917	8,026	46,151
2024	29,864	6,685	7,685	44,233
2025	29,745	6,365	7,211	43,322
2026	27,211	6,118	6,884	40,213
2027	27,676	6,011	6,699	40,385
2028	23,720	5,900	6,682	36,302
2029	20,698	5,377	5,956	32,031
2030	16,127	4,198	4,440	24,765
2031	15,130	3,561	3,710	22,401
2032	14,657	3,368	3,431	21,456
2033	13,082	3,196	3,106	19,384
2034	10,956	2,950	2,669	16,574
2035	11,841	2,840	2,440	17,122
2036	11,478	2,711	2,335	16,525
Nominal Value	**$467,068**	**$99,330**	**$109,419**	**$675,817**
Present Value	**$235,518**	**$47,091**	**$52,805**	**$335,414**

Table 19

Attachment 1

Smart Grid Foundation Project

Exhibit G

Pre-In-Service/Go-Live Expense Details

PRE-IN-SERVICE/GO-LIVE EXPENSE DETAILS

As described in Section VI.A.2 of the accompanying Exhibit, the following tables provide a further detailed breakdown of the Pre-In-Service/Go-Live Expenses by Smart Grid Foundation Project ("SGF Project") subproject, cost category detail and year.

AMI Subproject Pre In-Service Expenses by Year (Nominal $000s)						
Cost Category Detail	2017	2018	2019	2020	2021	Total
Outside Services - Cellular	44	204	207	-	-	455
Maintenance	1,714	1,455	1,000	88	85	4,342
Incremental Internal Labor - PMO	85	27	26	4	4	145
Outside Services - PMO	46	14	14	2	-	76
Internal Labor - Training	230	-	-	-	-	230
Outside Services - Training	2,827	-	-	-	-	2,827
Miscellaneous	111	45	30	2	2	190
Total	**5,056**	**1,744**	**1,277**	**96**	**91**	**8,265**

Table 1

CFS Subproject Pre In-Service Expenses by Year (Nominal $000s)						
Cost Category Detail	2017	2018	2019	2020	2021	Total
Maintenance	394	220	220	-	-	835
Internal Labor - PMO	9	4	6	1	-	22
Outside Services - PMO	5	2	3	1	-	12
Internal Labor - Training	96	41	56	21	-	214
Outside Services - Training	37	15	20	7	-	80
Miscellaneous	14	6	8	-	-	28
Total	**556**	**289**	**314**	**31**	**-**	**1,190**

Table 2

CVR Subproject Pre In-Service Expenses by Year (Nominal $000s)						
Cost Category Detail	2017	2018	2019	2020	2021	Total
Maintenance	302	603	728	776	786	3,195
Internal Labor - PMO	6	10	15	34	34	98
Outside Services - PMO	3	5	8	20	4	40
Internal Labor - Training	-	-	-	-	-	-
Outside Services - Training	-	-	-	-	-	-
Miscellaneous	19	15	13	14	14	75
Total	**330**	**633**	**765**	**843**	**838**	**3,408**

Table 3

DLC Subproject Pre In-Service Expenses by Year (Nominal $000s)						
Cost Category Detail	2017	2018	2019	2020	2021	Total
Maintenance	162	162	166	208	157	855
Internal Labor - PMO	3	3	3	10	7	26
Outside Services - PMO	2	1	2	6	1	11
Internal Labor - Training	-	-	-	-	-	-
Outside Services - Training	-	-	-	-	-	-
Miscellaneous	-	-	-	17	17	34
Total	**166**	**166**	**171**	**240**	**183**	**926**

Table 4

MDMS Subproject Pre In-Service Expenses by Year (Nominal $000s)						
Cost Category Detail	2017	2018	2019	2020	2021	Total
Maintenance	885	989	998	-	-	2,873
Internal Labor - PMO	19	22	28	-	-	69
Outside Services - PMO	10	12	15	-	-	37
Internal Labor - Training	-	235	215	-	-	450
Outside Services - Training	-	88	76	-	-	165
Miscellaneous	188	97	80	-	-	365
Total	**1,102**	**1,444**	**1,414**	**-**	**-**	**3,960**

Table 5

OMS Subproject Pre In-Service Expenses by Year (Nominal $000s)						
Cost Category Detail	2017	2018	2019	2020	2021	Total
Outside Services - Data Migration	2,229	1,959	-	-	-	4,188
Maintenance	93	329	584	-	-	1,007
Internal Labor - PMO	41	37	19	-	-	96
Outside Services - PMO	22	20	10	-	-	52
Internal Labor - Training	-	-	198	-	-	198
Outside Services - Training	-	-	70	-	-	70
Miscellaneous	-	59	53	-	-	112
Total	**2,385**	**2,405**	**934**	**-**	**-**	**5,724**

Table 6

Attachment 2

Smart Grid Foundation Project

Exhibit G

Ongoing Cost Details

ONGOING COST DETAILS

As described in Section VI.A.3 of the accompanying Exhibit, the Hawaiian Electric Companies ("Companies") have post-in-service/go-live ongoing operational support, maintenance and lifecycle management expenses ("Ongoing Costs") associated with the assets implemented as part of the Smart Grid Foundation Project ("SGF Project"). The nominal value for these Ongoing Costs is $34 million incurred in the period between each subproject's in-service/go-live dates and each company's first rate cases post the SGF Project completion (i.e., 2017 through 2024).

These costs are included in the revenue requirements calculation presented for the purposes of estimating the potential bill impact that each utility's customers can expect. Table 1 below, provides the consolidated tri-company view of these costs.

Consolidated SGF Project Ongoing Costs by Subproject and Year (Nominal $000s)									
Component	2017	2018	2019	2020	2021	2022	2023	2024	Total
AMI	-	501	1,627	2,685	2,734	7,563	1,188	-	16,298
CFS	-	-	-	-	773	791	-	-	1,564
CVR	-	-	-	-	-	2,295	407	-	2,702
DLC	-	-	-	-	-	-	-	-	-
EDW	-	-	-	-	-	1,397	-	-	1,397
ESB	-	-	-	-	-	1,332	-	-	1,332
MDMS	-	-	-	1,930	2,137	2,227	-	-	6,293
OMS	-	-	-	1,435	1,476	1,198	316	-	4,425
Total	**-**	**501**	**1,627**	**6,050**	**7,120**	**16,803**	**1,912**	**-**	**34,012**

Table 1

Sections I through III below, show a breakout for each utility's Ongoing Costs, by year and accounting treatment, through to each company's first rate case filings after the SGF Project is completed. The Renewable Energy Infrastructure Program ("REIP") surcharge ("Surcharge") is proposed to be from 2017 through to each company's first rate case filings after the SGF Project is completed.

I. HAWAIIAN ELECTRIC SGF PROJECT ONGOING COSTS

As shown in Table 2 below, the nominal value of the SGF Project Ongoing Costs incurred by Hawaiian Electric is approximately $26 million. Following the SGF Project completion in 2021, the first rate case filing for Hawaiian Electric is scheduled in 2023. Therefore, the costs presented in this section are reflective of all Ongoing Costs incurred between 2017 through 2022.

Table 2 below, shows these same Ongoing Costs by subproject and year for Hawaiian Electric during the period in which the Ongoing Costs will be applied through the REIP Surcharge.

Hawaiian Electric SGF Project Ongoing Costs by Subproject and Year (Nominal $000s)							
Component	2017	2018	2019	2020	2021	2022	Total
AMI	-	501	1,353	1,698	1,728	6,133	11,413
CFS	-	-	-	-	773	791	1,564
CVR	-	-	-	-	-	1,713	1,713
DLC	-	-	-	-	-	-	-
EDW	-	-	-	-	-	1,397	1,397
ESB	-	-	-	-	-	1,332	1,332
MDMS	-	-	-	1,930	2,137	2,227	6,293
OMS	-	-	-	800	824	864	2,488
Total	**-**	**501**	**1,353**	**4,428**	**5,462**	**14,457**	**26,200**

Table 2

II. HAWAI‘I ELECTRIC LIGHT SGF PROJECT ONGOING COSTS

As shown in Table 3 below, the nominal value of the Ongoing Costs incurred by Hawai‘i Electric Light is approximately $2 million. Following the SGF Project completion in 2021, the first rate case filing for Hawai‘i Electric Light is scheduled in 2022. Therefore, the costs presented in this section are reflective of all Ongoing Costs incurred between 2017 through 2021.

Table 3 below, shows these same Ongoing Costs by subproject and year for Hawai‘i Electric Light during the period in which the Ongoing Costs will be applied through the REIP Surcharge.

Hawai‘i Electric Light SGF Project Ongoing Costs by Subproject and Year (Nominal $000s)						
Component	2017	2018	2019	2020	2021	Total
AMI	-	-	150	558	569	1,276
CFS	-	-	-	-	-	0
CVR	-	-	-	-	-	0
DLC	-	-	-	-	-	0
EDW	-	-	-	-	-	0
ESB	-	-	-	-	-	0
MDMS	-	-	-	-	-	0
OMS	-	-	-	327	336	663
Total	**-**	**-**	**150**	**885**	**905**	**1,939**

Table 3

III. MAUI ELECTRIC SGF PROJECT ONGOING COSTS

As shown in Table 4 below, the nominal Ongoing Costs incurred by Maui Electric is approximately $6 million. Following the SGF Project completion in 2021, the first rate case filing for Maui Electric is scheduled in 2024. Therefore, the Ongoing Costs presented in this section are reflective of all Ongoing Costs incurred between 2017 through 2023.

Table 4 below shows these same Ongoing Costs by subproject and year for Maui Electric during the period in which the Ongoing Costs will be applied through the REIP Surcharge.

Maui Electric SGF Project Ongoing Costs by Subproject and Year (Nominal $000s)								
Component	2017	2018	2019	2020	2021	2022	2023	Total
AMI	-	-	124	429	438	1,430	1,188	3,609
CFS	-	-	-	-	-	-	-	0
CVR	-	-	-	-	-	582	407	989
DLC	-	-	-	-	-	-	-	0
EDW	-	-	-	-	-	-	-	0
ESB	-	-	-	-	-	-	-	0
MDMS	-	-	-	-	-	-	-	0
OMS	-	-	-	308	316	334	316	1,274
Total	**-**	**-**	**124**	**737**	**754**	**2,346**	**1,912**	**5,873**

Table 4

Exhibit H

Smart Grid Foundation Project

Non-Standard Meter Service Tariff

SHEET NO.
Effective

NON-STANDARD METER SERVICE

Supplement To

Schedule R	- Residential Service
Schedule G	- General Service - Non-Demand
Schedule J	- General Service - Demand
Schedule DS	- Large Power Directly Served Service
Schedule P	- Large Power Service
Schedule F	- Public Street Lighting, Highway Lighting and Park and Playground Floodlighting
Schedule U	- Time-of-Use Service
Schedule TOU-R	- Residential Time-of-Use Service
Schedule TOU-G	- Small Commercial Time-of-Use Service
Schedule TOU-J	- Commercial Time-of-Use Service
Schedule SS	- Standby Service
Schedule TOU EV	- Residential Time-of-Use Service with Electric Vehicle Pilot
Schedule EV-R	- Residential Electric Vehicle Charging Service Pilot
Schedule EV-C	- Commercial Electric Vehicle Charging Service Pilot

All terms and provisions of the above listed rate schedules are applicable except that the total base rate charges for each billing period shall be increased by the Non-Standard Meter Charge and the Non-Standard Meter Setup Charge, where applicable.

NON-STANDARD METER CHARGE:

Applicability:

Standard service shall be provided by an Advanced Metering Infrastructure (“AMI” or “smart”) meter. Customers may elect to be served through a non-standard meter by request to the Companies. Customers who elect such Non-Standard Meter Service will have their meter read manually and the provisions of Rule No. 8, A., 2 for metered service will apply.

Non-Standard Meter Service will also apply to a customer’s service location where the Companies are unable to access the property to install the standard service AMI meter.

The following charge will be assessed to each customer for Non-Standard Meter Service per normal billing month:

NON-STANDARD METER CHARGE ....$15.30 per month

HAWAIIAN ELECTRIC COMPANY, INC.

Transmittal Letter dated

SHEET NO.
Effective

NON-STANDARD METER SERVICE (continued)

The above charge shall apply in addition to any applicable customer charge or minimum charge that is assessed per the terms and conditions of the customer's regular rate schedule service.

NON-STANDARD METER SETUP CHARGE:

Applicability:

Standard service shall be provided by an AMI meter. Customers may elect to be served through a non-standard meter by request to the Company. Where existing service is provided through an AMI meter and the customer elects to change to Non-Standard Meter Service, the customer shall be billed a one-time Non-Standard Meter Setup Charge on the electric bill in addition to the Non-Standard Meter Charge, as follows:

NON-STANDARD METER SETUP CHARGE

For Single Phase Service.............$49.32

For Polyphase Service $313.74

The above charge shall apply in addition to any applicable customer charge or minimum charge that is assessed per the terms and conditions of the customer's regular rate schedule service.

LIMITATIONS ON NON-STANDARD METER SERVICE:

Customers served on Non-Standard Meter Service will not be eligible for:

1. Time-of-Use rate options, Real-Time Pricing rate options or any other time-interval dependent programs;
2. Distributed Energy Resource programs; or
3. Any programs that would normally require service through an AMI meter.

Customers who are enrolled in any of the above service(s) or program options prior to the establishment of standard service through AMI meters will not be grandfathered on Non-Standard Meter Service, and must take Standard AMI Meter Service through an AMI meter to maintain enrollment in any of the above service or program options.

NON-STANDARD METER SERVICE (continued)

CONVERSION TO STANDARD AMI METER SERVICE:

Customers served through Non-Standard Meter Service may convert to Standard AMI Meter Service at any time upon request to the Company. Where existing service is provided through a non-standard meter and the customer elects to change to Standard AMI Meter Service, upon meter change, the customer shall no longer be billed the Non-Standard Meter Charge.

RULES AND REGULATIONS:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Attachment 1

Smart Grid Foundation Project

Exhibit H

Non-Standard Meter Service Program Fees

NON-STANDARD METER SERVICE PROGRAM FEES

I. SETUP CHARGE FEES

As part of the Smart Grid Foundation Project ("SGF Project"), customers who wish to have an installed smart meter exchanged with a digital, non-smart/non-AMI meter ("Non-Standard Meter") will be charged an exchange fee ("Setup Charge"), which will be applied on a pro-rated basis to the customer's current billing cycle. This Setup Charge is shown in the row labeled *Tri-Company Average for Single Phase Meters and Polyphase Meters* in Table 1, below.

Customers who have a Non-Standard Meter upon enrollment in the Non-Standard Meter ("NSM") Service Program are not charged this Setup Charge. In the row labeled *Calculation*, Setup Charges are multiplied by a factor for the meter phase type (which is a ratio of the expected number of monthly meter reads for that company compared to the expected number of monthly meter reads for all companies) for Hawaiian Electric, Maui Electric and Hawai‘i Electric Light, respectively, to get the *Tri-Company Average Setup Charge* for that phase type. These fees are provided in Table 1, below.

NSM Service Program – Setup Charges ($)		
Company	Single Phase	Polyphase
Hawaiian Electric (A)	40.82	282.05
Maui Electric (B)	59.45	370.51
Hawai‘i Electric Light (C)	60.94	375.11
(Calculation)	(A x 0.5630) + (B x 0.1966) + (C x 0.2404)	(A x 0.6494) + (B x 0.2032) + (C x 0.1474)
Tri-Company (Avg.)	**49.32**	**313.74**

Table 1

The NSM Single Phase ("Single Phase") meter Setup Charge consists of labor, non-labor, and testing costs. Labor costs consist of the labor needed by a Field Service Representative ("FSR") to remove a previously installed smart meter and replace it with a Non-Standard Meter in a given service area. Non-labor costs consist of a vehicle cost on a per year basis used in conjunction with the meter exchanges. Testing costs consist of the labor for a meter tester to test the Non-Standard Meter prior to installation.

In the line labeled *Calculation*, the individual Company Setup Charges are multiplied by a factor (which is derived from the ratio of the expected transaction load for the Single Phase category for that company compared to all service areas for the Single Phase category) to get the *Tri-Company Average Setup Charge for Single Phase* meters. Sub-calculations show precision to the nearest cent with rounding. These assumptions are provided in Table 2, below.

Setup Charge Costing Assumptions – Single Phase ($)			
Company	Labor Costs	Non-Labor Costs	Testing Costs
Hawaiian Electric (A)	25.74	1.74	13.33
Maui Electric (B)	41.82	4.06	13.57
Hawai'i Electric Light (C)	43.57	3.80	13.57
(Calculation)	(A x 0.5630) + (B x 0.1966) + (C x 0.2404)		
Tri-Company (Avg.)	**33.19**	**2.69**	**13.43**

Table 2

The Polyphase Meter ("Polyphase") Setup Charge consists of labor, non-labor, and testing costs. Labor costs consist of the labor needed by a meter electrician to remove a smart meter and install a Non-Standard Meter in a given service area. This labor is set at the overtime amount since the meter electrician will be working on the SGF Project smart meter deployment full time. Non-labor costs consist of the vehicle cost on a per year basis used in conjunction with the meter exchanges. Testing costs consist of the labor for a meter tester to test the Non-Standard Meter prior to installation.

In the line labeled *Calculation*, the individual Company Setup Charges are multiplied by a factor (which is derived from the ratio of the expected transaction load for the Polyphase category for that company compared to all service areas for the Polyphase category) to get the *Tri-Company Average Setup Charge for Polyphase* meters. Sub-calculations show precision to the nearest cent with rounding. These assumptions are provided in Table 3, below.

Setup Charge Costing Assumptions – Polyphase ($)			
Company	Labor Costs	Non-Labor Costs	Testing Costs
Hawaiian Electric (A)	258.44	5.68	17.93
Maui Electric (B)	342.43	10.14	17.93
Hawai'i Electric Light (C)	347.56	9.29	18.26
(Calculation)	(A x 0.6494) + (B x 0.2032) + (C x 0.1474)		
Tri-Company (Avg.)	**288.64**	**7.12**	**17.98**

Table 3

II. MONTHLY FEES

Customers enrolled in the NSM Service Program will be charged monthly fees on a per meter basis regardless of phase type. This monthly fee is shown in Table 4 below on the *Tri-Company Average* line. Customers who enroll in the NSM Service Program will have this this monthly fee applied to their monthly bill through a pro-rated rate if applicable when they enroll in the program, depending on the timing of their billing cycle, then at the regular, standard rate for each bill cycle that follows.

In the row labeled *Calculation*, the individual monthly fees per Company are multiplied by a factor which is the ratio of expected transaction load for that Company compared to all service areas to get the *Tri-Company Average Monthly Fee*. Actual costs were calculated on an entire service area basis to obtain the *Tri-Company Average for the Monthly Fee*, so the calculation may differ by 1 cent or less, as shown in Table 4, below.

NSM Service Program – Monthly Fees ($)	
Company	Single Phase or Poly Phase
Hawaiian Electric (A)	15.11
Maui Electric (B)	14.44
Hawai‘i Electric Light (C)	16.48
(Calculation)	(A x 0.5643) + (B x 0.1967) + (C x 0.2390)
Tri-Company (Avg.)	**15.30**

Table 4

The monthly fee consists of labor, non-labor, equipment costs, and shifted costs. Labor costs consist of the labor needed by a FSR to both read and service a Non-Standard Meter. Non-labor costs consist of the vehicle cost information as provided by the Fleet Division, which takes into account the entire cost for the vehicle on a per year basis, and from licensing costs for use of hand held units for meter reading used in conjunction with manually reading the meters. Equipment costs consist of the upgrade costs of the hand held units used for meter reading which is done every seven years. Shifted costs are back-office system setup costs which are spread among all customers on a monthly transaction basis to support the manual monthly billing process.

The line labeled *Calculation* multiplies the individual Company Setup Charges by a factor which is the ratio of the expected transaction load for that Company compared to all service areas to get the *Tri-Company Average Monthly Fee*. Actual costs were calculated on an entire service area basis to obtain the *Tri-Company Average for the Monthly Fee*, so the calculation may differ by 1 cent or less. These assumptions are provided in Table 5, below.

Monthly Fee Costing Assumptions ($)				
	Labor Costs	Non-Labor Costs	Equipment Costs	Shifted Costs
Hawaiian Electric (A)	13.22	1.11	0.10	0.39
Maui Electric (B)	12.89	1.45	0.09	0.39
Hawai‘i Electric Light (C)	14.84	1.53	0.11	0.39
(Calculation)	(A x 0.5643) + (B x 0.1967) + (C x 0.2390)			
Tri-Company (Avg.)	**13.54**	**1.27**	**0.10**	**0.39**

Table 5

Attachment 2

Smart Grid Foundation Project

Exhibit H

Non-Standard Meter Service Program Customer Enrollment Form

Hawaiian Electric
Maui Electric
Hawaiʻi Electric Light

Non-Standard Meter Service Program Customer Enrollment Form

(Please use a separate form for each account and physical address of service)

I, a customer of Hawaiian Electric / Maui Electric / Hawaiʻi Electric Light ("Companies"), hereby elect to have the Companies (1) not install any smart meter ("Standard Meter") in connection with my below-listed account, or (2) remove any Standard Meter currently installed in connection with my below-listed account, and (3) replace any removed meter with a digital non-smart meter ("Non-Standard Meter") (as that term is defined in Rule No. XX of the Companies' Tariff No. X).

By completing and submitting this form, I understand and agree that: (a) I will not receive the benefits of a Standard Meter, which include, but are not limited to: an energy management tool that can help me track my energy usage to better manage energy costs; enhanced metering capabilities that may allow me to enroll in future rate programs; remote outage troubleshooting that can shorten power outages; automated meter reading; and (b) I am responsible for paying any applicable Non-Standard Meter exchange One Time Charge of $XX.XX for Single Phase meters or $XXX.XX for Poly Phase meters if a standard meter has already been installed, as well as a monthly charge of $XX.XX, set forth in Rule No. XX of the Companies' Tariff No. X. I understand that the applicable charges set forth in Rule No. XX of the Companies' Tariff No. X may be amended from time to time and I am responsible for paying any applicable amended charges[1].

I also understand and agree that I am responsible for providing and maintaining monthly access to the Companies for purposes of meter installation, maintenance, and reading. Failure to provide and maintain access to the Companies will result in my service being terminated pursuant to Rule Nos. XX, XX, and XX of the Companies' Tariff No. XX.

1. The one-time set-up charge includes the cost of labor involved with performing the meter exchange, if applicable. The monthly charge includes fixed costs of maintaining service to your house/facility such as sending a meter reader to physically read your Non-Standard Meter.

Customer name (printed): ____________________

Customer signature: ____________________

Date: ____________ Account Number: ____________________

Electric Company: ☐ Hawaiian Electric ☐ Maui Electric ☐ Hawaiʻi Electric Light

Physical Address of Service: ____________________

____

____

Phone Number to verify: ____________________

OFFICE USE ONLY:

Meter Change Req		Charge	Quantity
Single Phase	☐	$49.32	_______
Poly Phase	☐	$313.74	_______
No Change	☐	$0.00	_______

Date form received: ____________

Verification of customer account ☐

Submit by mail or in person on or before XX/XX/XXXX (X Calendar Weeks):

Hawaiian Electric Honolulu Payment Center • 1001 Bishop Street, 1st floor lobby, Honolulu, HI 96913
Maui Electric Kahului Payment Center • 210 W Kamehameha Avenue, Kahului, Maui 96732
Hawaiʻi Electric Light Hilo Payment Center • 1200 Kilauea Avenue Hilo, HI 96720
Hawaiʻi Electric Light Kona Payment Center • 74-5519 Kaiwi Street Kailua-Kona, HI 96740

Questions or concerns? Please contact Smart Grid hotline at 8xx.xxx.xxxx Monday through Friday 7:30 AM to 6:00 PM

Exhibit I

Smart Grid Foundation Project

Merged Business Case

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Attachment 2 – Merged Cost Components by Company

Attachment 3 – Merged Outside Services Cost Details

Attachment 4 – Merged Project Management Office Cost Details

Attachment 5 – Merged Economic Analysis Details

MERGED BUSINESS CASE

I. EXECUTIVE SUMMARY

In Exhibit B to the accompanying application, the Hawaiian Electric Companies[1] have provided a business case for their Smart Grid Foundation Project ("SGF Project") that does not assume approval of the proposed change of control with NextEra Energy, Inc. ("NextEra Energy") that is pending in Docket No. 2015-0022 ("unmerged business case"). This exhibit provides a similar analysis, but under the assumption that the proposed change of control will be approved ("merged business case").

At a high level, the primary differences between this merged business case and the unmerged business case are related to the SGF Project costs and deployment schedule. The $318 million level of costs included in this merged business case is approximately $22 million or 6% lower than the unmerged business case costs of $340 million. The major drivers of these differences in costs are that: (1) deployment of smart meters, customer energy portal, and fixed and dynamic pricing plans would be accelerated from five to three years; (2) supply chain costs for some equipment and outside services would be reduced by 5%; (3) some solutions being used by NextEra Energy's subsidiary Florida Power & Light Company ("FPL") could be leveraged (e.g., FPL's MDMS and ESB); and (4) key FPL personnel would provide additional expertise, thus mitigating project execution risks.

II. MERGED SGF PROJECT DESCRIPTION

Since February 2015, a team of Smart Grid experts from NextEra Energy's subsidiary FPL has worked with the Companies' Smart Grid team to develop the SGF Project scope. As described in Attachment 1, the FPL team shared many experiences and provided many suggestions which have been adopted in the unmerged scenario. In addition to sharing its expertise, the FPL team was also asked to create a merged scenario under which the SGF Project would be executed in the event of a change of control.[2] The FPL team included a team leader with broad customer service experience, the expert who lead FPL's deployment of the mesh network and over 4.5 million smart meters, the Information Technology ("IT") expert who lead the implementation of many of the back office systems that support the Advanced Metering Infrastructure ("AMI") network, the expert responsible for cost and performance of FPL's deployment, an expert who lead the customer engagement and web tools implementation of Baltimore Gas & Electric's Smart Grid deployment, and an expert from FPL Power Delivery business unit who has responsibility for various Smart Grid areas at FPL. This core team was supported by various other subject matter experts, as needed.

The FPL team's approach to create a merged scenario first and foremost was to be responsive to the Hawai'i Public Utilities Commission's ("Commission") Inclinations

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[1] The "Hawaiian Electric Companies" or "Companies" are Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Maui Electric Company, Limited ("Maui Electric") and Hawaii Electric Light Company, Inc. ("Hawai'i Electric Light").

[2] See Application of Hawaiian Electric Companies and NextEra Energy for approval of the Proposed Change of Control ("Proposed Transaction") filed on January 29, 2015 in Docket No. 2015-0022.

document.[3] The team wanted to accelerate the foundational elements of the Smart Grid deployment in a realistic manner that managed the risks of technology, vendors, cost overruns and project delays. Additionally, the team wanted to reduce costs through purchasing power and leveraging existing contracts when it made sense to do so. The team adopted the motto of cheaper, faster and with lower risk.

- ***Cheaper*** – By leveraging NextEra Energy's purchasing power to reduce the overall cost to the customer of the merged SGF Project. Also, NextEra Enegy explored and incorporated ways to reduce costs by leveraging existing NextEra Energy or FPL contracts, vendors and/or solutions if it made sense to do so and delivered on the project requirements;

- ***Faster*** – The team recognizes that Hawai'i needs Smart Grid technology to be installed as quickly as possible to facilitate the reliable, secure, and efficient operations of the electrical grid and to provide customers with information that allows them to better manage their electricity needs. The merged scenario accelerates the deployment of smart meters, the customer energy portal, and fixed time-of-use ("TOU") and real-time pricing ("RTP") plans by two years; and

- ***Lower Risk*** – Smart Grid deployments are complex projects which consist of numerous internal and external resources that must be tightly managed to avoid issues that result in delays and cost overruns. Smart Grid deployments have risks, and when it comes to risk, <u>there is no substitute for experience</u>. The FPL team has already helped to reduce risk in the Companies' plans; however, risk exposure during the actual deployment is much greater. The FPL team has taken steps in the merged scenario to reduce the risk of the Companies' deployment through the utilization of proven systems, processes, and oversight.

The FPL team has spent a significant amount of time developing a merged scenario that is best for the State of Hawai'i and its residents while addressing the Commission's Inclinations.

A. <u>MERGED SGF PROJECT COMPONENTS</u>

Like the unmerged scenario, there are 10 components of the SGF Project (listed below), which include 8 subprojects (AMI, CFS, CVR, DLC, EDW, ESB, MDMS, and OMS) and 2 project-wide components (Customer Engagement and Project Management). Additionally, just like the unmergd scenario, cybsecurity, which is one of the most critical components of Smart Grid, is embedded in all aspects of the SGF Project. The FPL team also included in the merged scenario Project Management, the use of a project wide professional System Integrator to

[3] <u>See</u> Docket No. 2012-0036, Regarding Integrated Resource Planning; Decision and Order No. 32052, Exhibit A, *Commission's Inclinations on the Future of Hawaii's Electric Utilities* (April 28, 2014) [hereinafter, "Commission's Inclinations"]

coordinate the many back office related components of the project. FPL has utilized such resources in other large successful projects and feels strongly that it is necessary for the Companies' deployment.

(1) Advanced Metering Infrastructure ("AMI");
(2) Customer Facing Solutions ("CFS");
(3) Conservation Voltage Reduction ("CVR");
(4) Direct Load Control ("DLC");
(5) Enterprise Data Warehouse ("EDW");
(6) Enterprise Service Bus ("ESB");
(7) Meter Data Management System ("MDMS");
(8) Outage Management System ("OMS");
(9) Customer Engagement ("CE"); and
(10) Project Management ("PMO")

B. MERGED SGF PROJECT MANAGEMENT

In the event the merger is approved, NextEra Energy and the Companies will adopt a similar allocation of the PMO to the various components. The PMO costs are similar with minor adjustments in staffing and timeline, including the addition of a System Integrator that is not included in the unmerged scenario. Additionally, NextEra Energy will commit increased resources to the PMO and establish a Project Operational Advisory Committee which will consist of subject matter experts to oversee and provide support to the project components. Differences to the unmerged scenario are primarily due to:

- Reduced project cost due to reduced project timeline;
- Enhanced Change Management and Project Management Organization;
- Establishment of an advisory committee; and
- Utilization of a System Integrator.

1. Project Organizational Structure

The PMO in the merged scenario ensures that there is direct and certain accountability for the deployment in five categories: AMI, distribution, business transformation, technology, and business systems. Each area reports up to a single leader of the SGF Project who in turn reports to the sponsoring Hawaiian Electric Companies' executive. The SGF Project leader is also supported by two external parties, the System Integrator and Silver Spring Networks, Inc. ("SSNI"). A project controls organization supports the SGF Project with various administrative support functions. The entire project is overseen by a Project Operational Advisory Committee and ultimately by the Executive Steering Ccommittee. The organization will be made up of a mix of Hawaiian Electric Companies, NextEra Energy and external resources. With the exception of the aforementioned, it is undetermined at this time which positions will be filled by which resources. Figure 1 below depicts the organizational structure for the merged SGF Project.

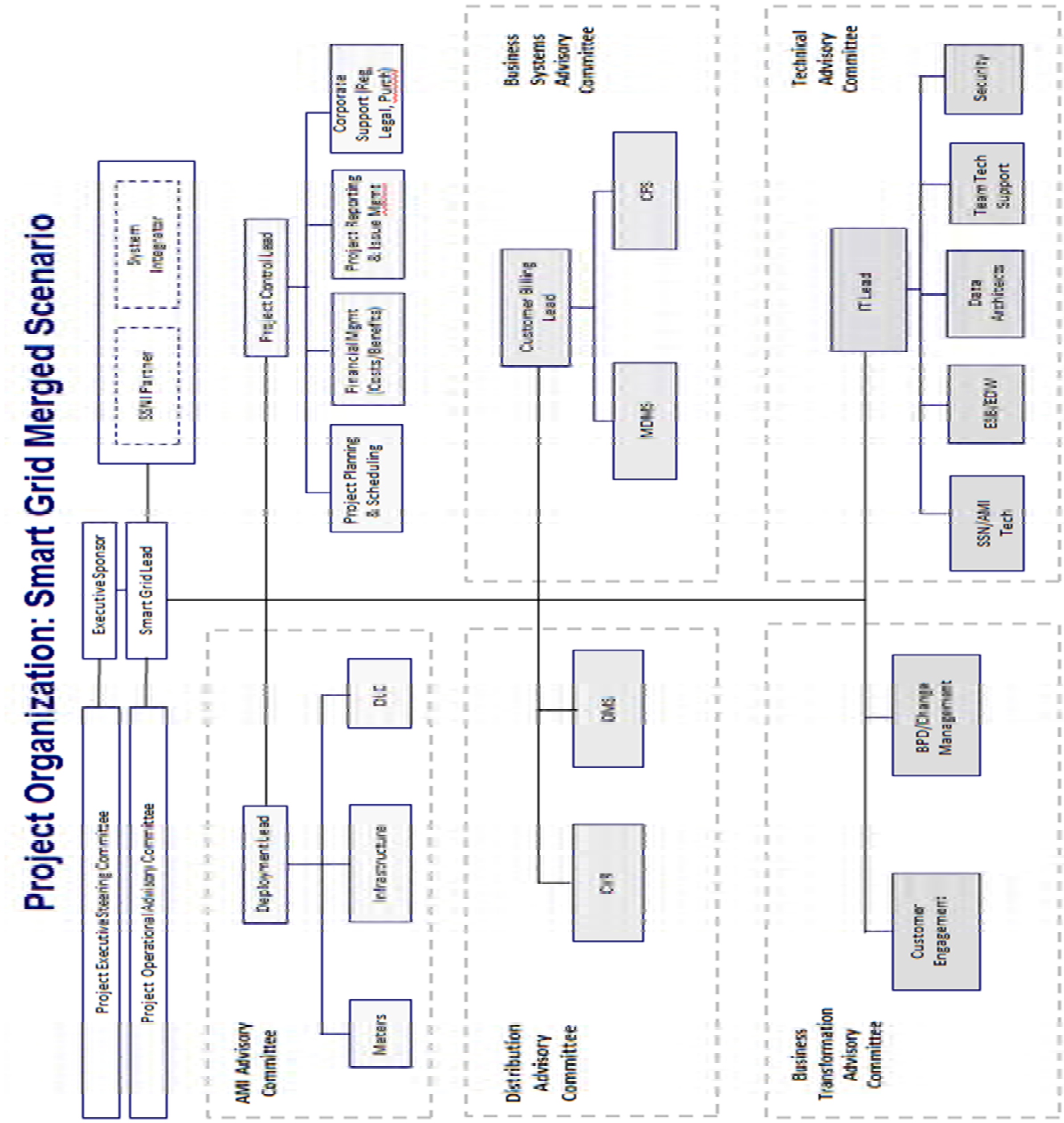
Project Organization: Smart Grid Merged Scenario
Project Executive Steering Committee
Project Operational Advisory Committee
Executive Sponsor
Smart Grid Lead
SSN Partner
System Integrator
Project Control Lead
Project Planning & Scheduling
Financial Mgmt (Costs/Benefits)
Project Reporting & Issue Mgmt
Corporate Support (Reg, Legal, Purch)
AMI Advisory Committee
Deployment Lead
Meters
Infrastructure
DLC
Distribution Advisory Committee
OMS
DMS
Business Systems Advisory Committee
Customer Billing Lead
MDMS
CPS
Business Transformation Advisory Committee
Customer Engagement
BPD/Change Management
Technical Advisory Committee
IT Lead
SSN/AMI Tech
ESB/EDW
Data Architects
Team Tech Support
Security

Figure 1

a. ***Project Executive Steering Committee***

The Executive Steering Committee is the highest level of oversight and authority for the project. The participants will hold positions at the Vice President ("VP") level or higher. It is undetermined at this time who or which positions would be on the Executive Steering Committee, however it will likely be those whose areas are most directly impacted by the project and those that have specific experience or skills to support the project.

b. ***Project Operational Advisory Committee***

The Operational Advisory Committee will play an important role in the deployment of Smart Grid in Hawaiʻi. The committee will consist of FPL employees who have experience executing the various components of Smart Grid in Florida. They will engage on a regular basis with the Companies' employees that are responsible for executing like components of the project in Hawaiʻi. This committee is the direct conduit for sharing best practices and addressing issues to facilitate a successful deployment in Hawaiʻi. Committee members will remain FPL employees and will only charge the portion of time spent working with the Companies' team to the Smart Grid project through NextEra Energy's affiliate charging mechanism. Since FPL employee involvement will be matched by skill set to specific components of the project, the number of employees and times in which they support will be dynamically changing over the five years of the project. The estimate for this support is two Full Time Equivalents ("FTEs").

c. ***Executive Sponsor***

The Executive Sponsor is the VP that has executive level responsibility for the successful deployment of the foundational project. This person will make high level decisions related to budgets, timeline, scope changes, and major issues. It has not been determined yet what VP position would be given this responsibility in a merged scenario.

d. ***Smart Grid Lead***

The Smart Grid Lead is the highest level resource whose time is one hundred percent dedicated to overseeing all aspects of the Smart Grid deployment. This person will have proven program management experience and success along with strong vendor management skills. The Smart Grid Lead must also be able to manage both internal and external resources. He or she will have ultimate accountability for the project timeline and budget. Each of the lead positions shown in the organizational chart will be direct reports to this position with the exception of the IT lead who will be a direct report to the Chief Information Officer with a strong dotted line to this position.

e. ***Project Control Lead***

The Project Control Lead handles the many administrative related functions associated with the project including, but not limited to cost and benefits tracking and reporting, tracking and reporting on project schedule and planning, Commission reporting, issues tracking and resolution, and coordinating activities with internal departments such as legal, purchasing, accounting, etc. This position is fully dedicated to the project and a member of the leadership team.

f. ***Deployment Lead***

This person is one hundred percent dedicated to successfully deploying the smart meters and the infrastructure needed to operate the network and all associated aspects of meter and network deployment as well as DLC. The Deployment Lead is a direct report to the Smart Grid Lead and will have direct reports working on various aspects of deployment. This position has responsibility for managing the meter vendors, the installation vendors, and SSNI issues related to the mesh network. He or she is responsible for making sure meters are tested in accordance with all requirements and that the appropriate level of inventory is available at all times. The Deployment Lead will have overall responsibility for meeting the meter deployment timeline.

g. ***CVR Lead***

This person is solely responsible for the successful implementation of all aspects of the CVR project working in conjunction with the IT lead. The CVR Lead will be a direct report to the Smart Grid Lead during the deployment of CVR.

h. ***OMS Lead***

This person is solely responsible for the successful implementation of all aspects of the OMS project working in conjunction with the IT lead described further below. The OMS Lead will be a direct report to the Smart Grid Lead during the deployment of OMS.

i. ***Customer Engagement Lead***

This person is solely responsible for the successful implementation of all customer engagement activities. The Customer Engagement Lead will work closely with various internal and external communication groups to ensure the communication plans are executed well.

j. ***Business Process Design and Change Management Lead***

There are many processes that will change as a result of the deployment of Smart Grid and it is important to have someone who is entirely focused on working with the various operational departments to prepare for and implement those changes. This position will lead that effort and will be a direct report to the Smart Grid Lead.

k. ***Billing Lead***

The Billing Lead is responsible for both the MDMS and CFS projects. This person will ensure all aspects of customer service processes including billing, customer communications, service orders, and revenue recovery are taken into account when delivering these projects. This role will work closely with the Business Process Design and Change Management Lead to ensure the transformation to using Smart Grid in the billing areas is successful. This role is fully dedicated to the project and will have project teams for both CFS and MDMS reporting to him/her.

l. ***IT Lead***

The IT Lead is responsible for all technical aspects of the SGF Project. This person will not only be directly responsible for the ESB, EDW and security projects, he or she will also be responsible for system design reviews, quality coding practices, security compliance, and providing technical leadership for the other IT components in the SGF Project such as MDMS, OMS, CVR, and CFS. This position will be a direct report to the Chief Information Officer with a strong dotted line to the Smart Grid Lead.

m. ***System Integrator***

In a project the size of Smart Grid, external capability and expertise will be needed to augment the Companies' internal staffing. The merged scenario utilizes a System Integrator to provide accountability and consistency across the projects within Smart Grid. The System Integrator will include a Senior Smart Grid Program manager who will carry the vendor responsibility throughout the program. In addition, the System Integrator will consist of many more resources in each of the SGF Project components including project managers, technical managers, business analysts, and technical resources. The System Integrator will work hand in hand with both the Companies' internal resources and the various other component vendor resources to ensure successful delivery of the project.

n. ***SSNI Partner***

SSNI is a key partner for the SGF Project and will have an overall engagement manager who will be the lead for this project working directly with the Companies. SSNI also plays a role in providing the smart meter technology, the infrastructure hardware, and various components of key software including the back office head-end software for collection of Smart Grid data. SSNI will have numerous resources both dedicated and part time allocated to different components of the project such as infrastructure installation, meter deployment, network optimization, and system integrations. SSNI brings additional value through providing lessons learned and best practices for the project.

2. Project Risk Management

NextEra Energy has already worked with the Companies to reduce risk by providing its FPL team of Smart Grid experts to share best practices and experience gained. Although much knowledge has been shared, the full benefit of NextEra Energy's experience will only be realized if the Proposed Transaction is approved, as detailed in Attachment 1.

In the event the Proposed Transaction is approved, NextEra Energy and the Companies will leverage FPL's extensive experience in Smart Grid deployment and operation to substantially reduce all five primary risks associated with: (1) knowledge and program risk, (2) technology risk, (3) operational risk, (4) customer adoption risk, and (5) vendor risk. The process by which NextEra Energy would approach these risks is further detailed below.

a. Knowledge and Program Risks

Knowledge and program risks would be reduced substantially because the Companies would have the full, ongoing, benefit of FPL's recent, successful, Smart Grid experience. While the Companies have consulted with their industry peers, including FPL, and have learned through pilot projects, the merged scenario will provide ongoing deployment guidance to the Companies through the Project Operational Advisory Committee composed of seasoned experts in Smart Grid deployment and technology. NextEra Energy firmly believes that when it comes to reducing risk, there is no substitute for experience.

b. Technology Risks

Technology risks relate to managing the integration of diverse vendor solutions into a seamlessly-functioning Smart Grid. In the merged scenario, the Companies will benefit from FPL's broad IT skill set and deep bench strength in key Smart Grid technologies which would be shared by the merged companies, including SSNI (FPL operates the second largest deployment of SSNI technology in the world), ESB, MDMS and enhanced EDW. In addition, as mentioned above, in the merged scenario a System Integrator will be used. The System Integrator role reduces delivery risk by creating clear accountability for ensuring that individual Smart Grid technology projects stay on track and successfully support the business process changes that deliver value to the Companies and their customers.

c. Operational Risks

Operational risks relate to ensuring Smart Grid performance to deliver the benefits identified. Under the merged scenario, the Companies will have access to the diagnostic tools, processes and skills already in use at FPL's state-of-the-art Smart Meter Operations and Diagnostic Center, saving the Companies years of development time and helping ensure Hawai'i's Smart Grid remains secure and reliable. FPL's Smart Meter Operations and Diagnostic Center is responsible for proactively monitoring and managing the network, accurately identifying and quickly resolving potential network communications issues, ensuring newly deployed sections of Smart Grid are ready to support business operations, and continue to operate smoothly afterwards.

d. Customer Adoption Risks

Customer adoption risks relate to customer acceptance of smart meters and Smart Grid services. Under a merged scenario, the merged Companies will follow a phased communication approach, developed with insights from NextEra Energy's recent experience deploying smart meters. The phased approach includes plans for providing individual customers with the proper advance notice of the new meter, communication at replacement and communication upon meter activation, all conducted in a supportive context of informed media, government officials, first responders and community stakeholders. Consistent with the guidelines in Commission's Inclinations to focus on "delivering immediate value and benefits to customers"[4] the merged

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[4] See Commission's Inclinations, Page 14.

Companies will also commit increased resources to the Customer Energy Portal to further reduce implementation risk and increase customer adoption rates. Finally, the merged Companies will accelerate the time-variant rate capabilities consistent with the guidelines in the Commission's Inclinations to support "rapid adoption of innovative rate structures."[5] These commitments are detailed in Attachment 1.

e. ***Vendor Risks***

Vendor risk relates to vendor delivery contracted Smart Grid products and services. A team of FPL Smart Grid experts worked with the Companies throughout 2015 on administering Requests For Proposal and statements of work. During the exchange, FPL experts shared extensively from their experience with potential Smart Grid vendors. In the merged scenario, the Companies would use the same vendors for several applications in order to extend NextEra Energy's success with their solutions to the benefit of the Companies, as well as achieve economies of time and scale by operating under existing vendor agreements.

C. MERGED SGF PROJECT SCHEDULE

The SGF Project is scheduled to begin immediately upon the issuance of a decision and order enabling the project to commence. The five year deployment period is the same as the unmerged scenario. The merged scenario, however, accelerates the deployment of smart meters and associated billing and customer portal systems along with dynamic pricing capabilities by two years. Acceleration of these components is possible because of the experience NextEra Energy brings to the project through the Project Operational Advisory Committee described earlier. This acceleration addresses the Commission's Inclinations report to move promptly with plans to deliver immediate benefits to customers by providing them access to view their energy consumption and improving service. The merged SGF Project schedule assumes the Companies' SGF Project is approved by August 2016.

Each component has its own schedule with its own deployment and in-service date(s) as illustrated in Figure 2 below. The red box represents the accelerated portion of the project compared to the unmerged.

[5] See Commissions Inclinations, Page 15.

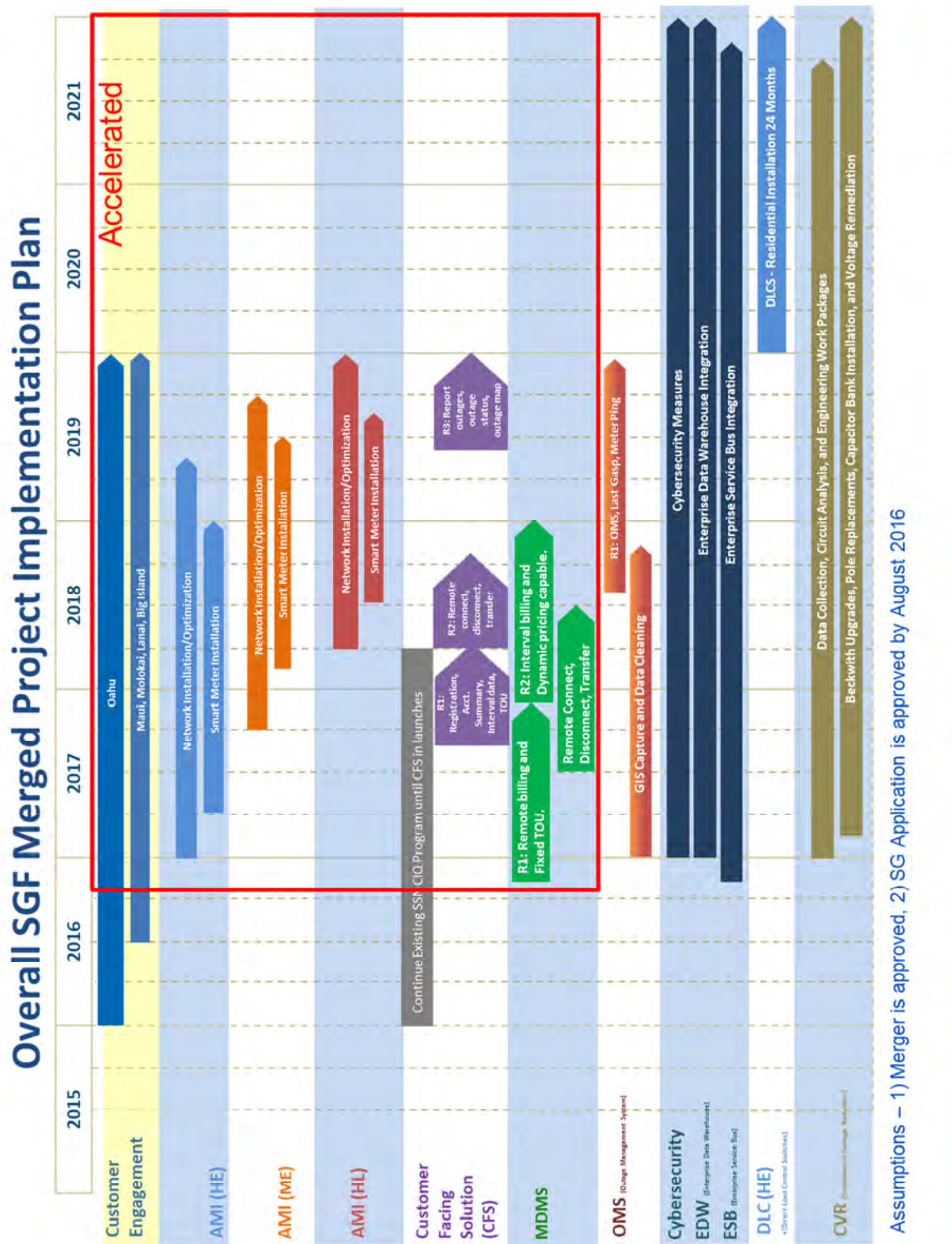

Figure 2

As in the unmerged scenario, the project is defined by two periods: Deployment and Ongoing. Deployment occurs throughout the first five years with some parts of the project beginning in year one and being placed into service before the five years end, and other parts of the project beginning in the later years and concluding by year five. Several parts of the project run the entire duration of the five years before being placed into service. The merged scenario timeline indicates a start date of October 2016 under an assumed August 2016 approval date of the accompanying application by the Commission. If the Proposed Transaction and the accompanying application are approved by August 2016, NextEra Energy advocates an early launch (i.e., October 2016) so that Hawaiʻi can experience the benefits of smart meters sooner, as outlined in the NextEra Energy's commitment described in Attachment 1. If approval is given later than August 2016 then the deployment and benefits would be delayed.

NextEra Energy would also work with the Companies to evaluate accelerating the later components of the SGF Project if acceleration makes sense as critical AMI and CFS deployments are ending in year three.

1. Merged Deployment Timeline

Deployment is a risky time for the SGF Project, when internal and external resources must be managed tightly to ensure the project remains on time and on budget. There is no substitute for experience in managing large projects during this period. There will be many vendors implementing their products into the Companies' existing systems, as well as into each others' systems. Decisions and actions by the project deployment team must be timely to remain on track. The merged project implementation timeline is aggressive, yet achievable with the right project management team in place and with support from the experienced Project Operational Advisory Committee outlined in Figure 1.

2. Merged Ongoing Timeline

Once each SGF Project component has been deployed and is fully functional, it is placed into service. Because the merged scenario accelerates certain SGF Project components, some will go into service sooner than in the unmerged scenario. As mentioned earlier, this can happen anytime between the 1-5 years of the implementation window. Costs beyond that point are no longer considered part of the project deployment and instead become part of ongoing costs. Ongoing costs include, but are not limited to, the cost of performance monitoring and network maintenance.

III. MERGED SGF PROJECT COSTS

In the event the Proposed Transaction is approved, the total cost for the Companies' merged SGF Project's implementation is estimated at $318 million, which is $22 million or approximately 6% less than the unmerged scenario.

Table 1 below shows the Merged and Unmerged SGF Project costs by component. The largest cost differences are in the MDMS, AMI, and ESB components primarily due to the accelerated deployment, project staffing, benefits in pricing of approximately 5% in select areas, and adoption of proven solutions used in FPL's smart grid.

Hawaiian Electric Companies' Un-merged and Merged Consolidated SGF Project Implementation Costs Comparison (Nominal $000)			
Component	Un-merged Scenario	Merged Scenario	Total
AMI	185,862	181,419	(4,443)
CFS	8,912	10,347	1,435
CVR	26,861	26,907	46
DLC	19,470	18,143	(1,327)
EDW	10,172	9,674	(498)
ESB	10,531	8,432	(2,099)
MDMS	51,725	36,840	(14,885)
OMS	18,091	18,085	(6)
CE	8,412	8,373	(39)
Total	**340,035**	**318,220**	**(21,816)**
Notes: 1) Includes all applicable taxes and Accumulated Funds Used During Construction ("AFUDC"). 2) PMO costs are allocated within each component.			

Table 1

NextEra Energy has categorized their costs by accounting treatment to mimic the Companies' existing accounting treatment policies (see Exhibit F to the accompanying Application for more information regarding the process used). Table 2 below shows the merged costs for the SGF Project's implementation by component and accounting treatment.

Hawaiian Electric Companies' Merged Consolidated SGF Project Implementation Costs by Accounting Treatment (Nominal $000)				
Component	Capital	Deferred	Expense	Total
AMI	156,695	7,506	17,218	181,419
CFS	601	7,161	2,585	10,347
CVR	21,771	1,138	3,998	26,907
DLC	16,544	675	924	18,143
EDW	2,105	3,208	4,361	9,674
ESB	1,047	4,176	3,209	8,432
MDMS	2,636	28,671	5,533	36,840
OMS	299	11,111	6,675	18,085
CE	-	-	8,373	8,373
Total	**201,698**	**63,646**	**52,876**	**318,220**
Notes: 1) Includes all applicable taxes and AFUDC. 2) PMO costs are allocated within each component.				

Table 2

Table 3, Table 4 and Table 5 below provide a similar cost presentation broken out by company and by accounting treatment. Additional details regarding these costs are provided in Attachment 2.

Merged Hawaiian Electric SGF Project Implementation Costs by Accounting Treatment (Nominal $000s)				
Component	Capital	Deferred	Expense	Total
AMI	98,043	7,506	11,148	116,697
CFS	600	7,161	2,586	10,347
CVR	11,963	1,138	2,616	15,717
DLC	16,544	675	924	18,143
EDW	2,105	3,208	4,361	9,674
ESB	1,047	4,176	3,209	8,432
MDMS	2,636	28,671	5,533	36,840
OMS	30	1,116	667	1,813
CE	-	-	6,620	6,620
Total	**132,968**	**53,651**	**37,664**	**224,283**
Note: 1) Includes all applicable taxes and AFUDC. 2) PMO costs are allocated within each component.				

Table 3

Merged Hawai'i Electric Light SGF Project Implementation Costs by Accounting Treatment (Nominal $000s)				
Component	Capital	Deferred	Expense	Total
AMI	32,965	-	3,066	36,031
CFS	-	-	-	-
CVR	5,327	-	760	6,087
DLC	-	-	-	-
EDW	-	-	-	-
ESB	-	-	-	-
MDMS	-	-	-	-
OMS	135	5,009	3,004	8,147
CE	-	-	877	877
Total	**38,426**	**5,009**	**7,707**	**51,142**
Notes: 1) Includes all applicable taxes and AFUDC. 2) PMO costs are allocated within each component.				

Table 4

Merged Maui Electric SGF Project Implementation Costs by Accounting Treatment (Nominal $000s)				
Component	Capital	Deferred	Expense	Total
AMI	25,688	-	3,003	28,691
CFS	-	-	-	-
CVR	4,481	-	622	5,104
DLC	-	-	-	-
EDW	-	-	-	-
ESB	-	-	-	-
MDMS	-	-	-	-
OMS	135	4,985	3,004	8,124
CE	-	-	877	877
Total	**30,304**	**4,985**	**7,506**	**42,795**
Notes: 1) Includes all applicable taxes and AFUDC. 2) PMO costs are allocated within each component.				

Table 5

A. COST-ESTIMATING METHODOLOGY

For the merged scenario, the FPL team used the unmerged cost model as a baseline to derive its costs. Therefore, the cost-estimating baseline for the merged scenario uses the same methodology which is described in the unmerged Business Case of the accompanying application (see Exhibit B). Working from the baseline, the FPL team made changes that matched or improved the functionality of the network while meeting the project requirements. In some cases the team was comfortable applying a cost savings on equipment that they felt could be procured at approximately 5% lower costs. The team also evaluated the ability to leverage existing solutions used at FPL that are delivered by vendors or built in house to meet the requirements of the project. Utilization of such proven solutions not only reduces costs, but significantly reduces risk.

1. Merged SGF Project Costing Assumptions

The cost assumptions under a merged scenario are based on the implementation schedule beginning in the fourth quarter of 2016, and, as further described in Attachment 1, reflect a proven, phased approach used in a smart meter deployment project in Florida, by starting on one island and expanding to two more islands, then completing the remaining two islands. The assumptions under a merged scenario include:

- Components that involve software (e.g., MDMS, CFS, OMS) will follow a combination of Agile and Waterfall project methodologies for each release phase;
- A combination of internal staff/employees, and/or external contractors and consultants will support the various components;
- External vendors and consultants will provide their own computing equipment which will be connected to the Companies' network via restricted and controlled access. All security requirements will be validated before granting access;

- Internal labor costs were estimated using a loaded employee rate provided by the Companies, which varies depending on the staff/employee position (and further described in each component breakdown below), with the loaded rate escalated for each year;

- Each component has its own specific in-service date and accompanying estimated costs, as further detailed in Section IV below;

- The merged scenario was developed based on 2016 dollars. The Companies calculated the impact of AFUDC, General Excise Taxes ("GET"), Gross Domestic Product Price Index ("GDPPI"), material overhead and labor increases. Table 6 below shows the AFUDC costs by component, by year:

Total SGF Project Merged AFUDC Implementation Costs by Year (Nominal $000s)						
Component	2016	2017	2018	2019	2020	2021
AMI	-	814	550	365	7	1
CFS	-	33	153	97	-	-
CVR	-	219	314	133	86	125
DLC	-	-	26	-	-	-
EDW	-	25	25	26	25	25
ESB	-	59	26	28	26	26
MDMS	-	637	598	-	-	-
OMS	-	-	131	531	-	-
CE	-	-	-	-	-	-
Total	-	**1,787**	**1,823**	**1,180**	**144**	**177**

Table 6

2. Merged Component Cost Categories

Table 7 below shows the breakdown of the merged SGF Project costs by year and by major cost category. All cost categories are defined the same as in the unmerged scenario, although the dollar amounts differ. There is one additional cost category listed in the merged scenario, Intercompany Labor, which includes the labor costs charged by the NextEra Energy's team to the Companies' SGF Project.

Merged SGF Project Total Implementation Costs by Cost Category and Year (Nominal $000s)							
Category	2016	2017	2018	2019	2020	2021	Total
Equipment	-	32,017	37,364	11,555	4,212	4,762	89,910
Hardware	2,427	3,142	457	303	246	483	7,058
Intercompany Labor	92	1,353	1,341	871	-	-	3,657
Internal Labor	210	12,746	22,561	16,213	5,090	6,088	62,908
Maintenance	804	4,025	3,934	2,928	2,059	2,018	15,768
Miscellaneous	110	705	607	487	91	64	2,064
Outside Services	944	50,151	40,072	20,772	7,118	6,832	125,889
Software	-	4,492	1,363	-	-	-	5,855
AFUDC	-	1,787	1,823	1,180	144	177	5,111
Total	**4,587**	**110,418**	**109,522**	**54,309**	**18,960**	**20,424**	**318,220**
Notes: 1) Includes all applicable taxes and AFUDC. 2) PMO costs are allocated within each component.							

Table 7

Additional details regarding outside services costs are provided in Attachment 3.

IV. MERGED SGF PROJECT COMPONENT COSTS

As indicated above, the estimated implementation cost of the SGF Project is $318 million under the merged scenario, approximately $22 million or 6% less compared to the unmerged scenario. The cost of the SGF Project's implementation under the merged scenario is broken down by component and cost category in Table 8, below:

Merged SGF Project Total Implementation Costs by Component and Cost Category (Nominal $000s)										
Component	Equip	HW	Inter - Comp	Internal Labor	Maintenance	Misc.	Outside Services	SW	AFUDC	Total
AMI	80,339	1,560	1,611	33,999	4,527	781	56,865	-	1,737	181,419
CFS	-	558	271	1,121	927	122	6,789	276	283	10,347
CVR	1,991	71	122	13,827	3,292	131	5,038	1,559	876	26,907
DLC	7,580	-	8	326	854	25	9,324	-	26	18,143
EDW	-	1,951	39	1,929	3,215	155	2,258	-	127	9,674
ESB	-	529	40	1,435	607	153	4,757	746	165	8,432
MDMS	-	2,142	1,255	5,608	2,031	380	21,582	2,607	1,235	36,840
OMS	-	247	269	2,723	315	299	12,903	667	662	18,085
CE	-	-	42	1,940	-	18	6,373	-	-	8,373
Total	**89,910**	**7,058**	**3,657**	**62,908**	**15,768**	**2,064**	**125,889**	**5,855**	**5,111**	**318,220**

Table 8

Sections IV.A through IV.J below provide detailed descriptions of each component with respect to the differences with those discussed in Exhibit B, along with their related costs for implementation, excluding AFUDC and PMO.[6]

A. ADVANCED METERING INFRASTRUCTURE

If the Proposed Transaction is consummated the smart meter and communication network deployment referred to as AMI will be accelerated by two years as outlined in Attachment 1, and the total AMI component cost will be reduced by approximately $7 million, as shown in Table 9, below.

AMI Implementation Costs Comparison by Cost Category (Nominal $000s)			
Cost Category	Unmerged Scenario	Merged Scenario	Difference
Equipment	81,750	80,339	(1,411)
Hardware	1,560	1,560	-
Intercompany	-	561	561
Internal Labor	39,746	31,701	(8,045)
Maintenance	4,860	4,527	(333)
Miscellaneous	501	781	280
Outside Services	50,086	52,043	1,957
Total	**178,503**	**171,512**	**(6,991)**
Note: Excludes AFUDC and PMO costs.			

Table 9

As described in Attachment 1, the estimated cost reduction under the merged scenario is primarily due to the shortened duration of project support costs under the accelerated deployment schedule (as shown in Figure 3, below), more effective use of contractor field resources for smart meter installations, and expected favorable smart meter hardware pricing.

[6] The estimates provided in this section are presented in nominal dollars (i.e., they have not been discounted to reflect the time value of money) and are exclusive of AFUDC and PMO in order to provide a clearer illustration of the underlying nominal costs.

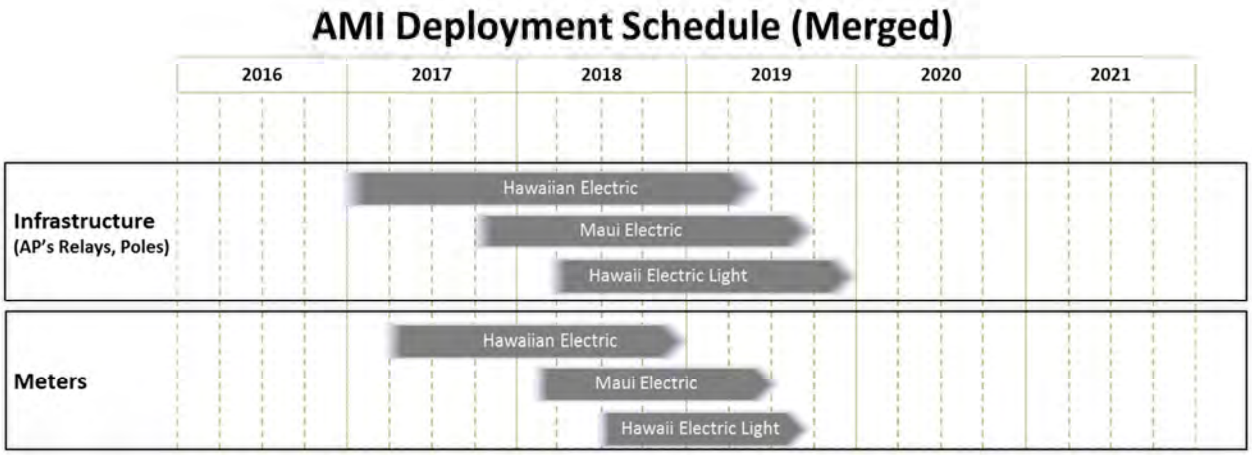

Figure 3

The accelerated Smart Grid deployment under the merged scenario will be made possible by fully leveraging contractor field resources for smart meter installations and NextEra Energy's project/contractor management experience from its Smart Grid implementation project. In addition, the Companies' selected smart meter manufacturer under the unmerged scenario is also a smart meter supplier for FPL, and more favorable smart meter pricing is expected under the merged scenario by leveraging NextEra Energy's considerable purchasing power and scale pricing.

The merged scenario cost estimate also includes the costs associated with implementing a Product Tracking System ("PTS") for Smart Grid assets and Space Time Insight ("STI") operational dashboards. The PTS solution, developed in-house by NextEra Energy in conjunction with its Smart Grid project, provides comprehensive end-to-end asset tracking and management (e.g., configuration, warranty, operational inventory, conditional monitoring) for smart meters, network devices and load control transponders. The cost associated with PTS in the merged scenario is $2.5 million. The comparable functionality in the unmerged scenario is contained in the unmerged case of the Companies' ERP/EAM Implementation Project Merger Impact Report filing in Docket No. 2014-0170. The STI operational dashboards were also developed in-house by NextEra Energy to provide a valuable set of tools for the Smart Grid operations teams to troubleshoot, diagnose, and monitor both the Smart Grid network and meter end points post deployment. The cost associated with the STI dashboard in the merged scenario is $2.3 million. The comparable functionality in the unmerged scenario is a vendor supplied service at a cost of $3.2 million.

B. CUSTOMER FACING SOLUTIONS

The total CFS component's implementation cost under the merged scenario is $1.2 million higher than under the unmerged scenario, primarily due to higher costs associated with hardware and outside services for an on premise solution versus the unmerged cloud solution. As shown in Table 10 below, under the merged scenario, NextEra Energy will commit additional dedicated resources to the CFS component to further reduce implementation risk and increase customer adoption rates.

CFS Implementation Costs Comparison by Cost Category (Nominal $000s)			
Cost Category	Unmerged Scenario	Merged Scenario	Difference
Hardware	-	558	558
Intercompany	-	201	201
Internal Labor	1,088	971	(117)
Maintenance	1,056	927	(129)
Miscellaneous	67	122	55
Outside Services	6,157	6,523	366
Software	-	276	276
Total	**8,368**	**9,578**	**1,210**
Note: Excludes AFUDC and PMO costs.			

Table 10

In order to implement the enhanced CFS, the merged scenario will introduce the CFS to customers through three separate phases (as opposed to four separate phases under the unmerged scenario). Figure 4 below shows the overall CFS component under the merged scenario:

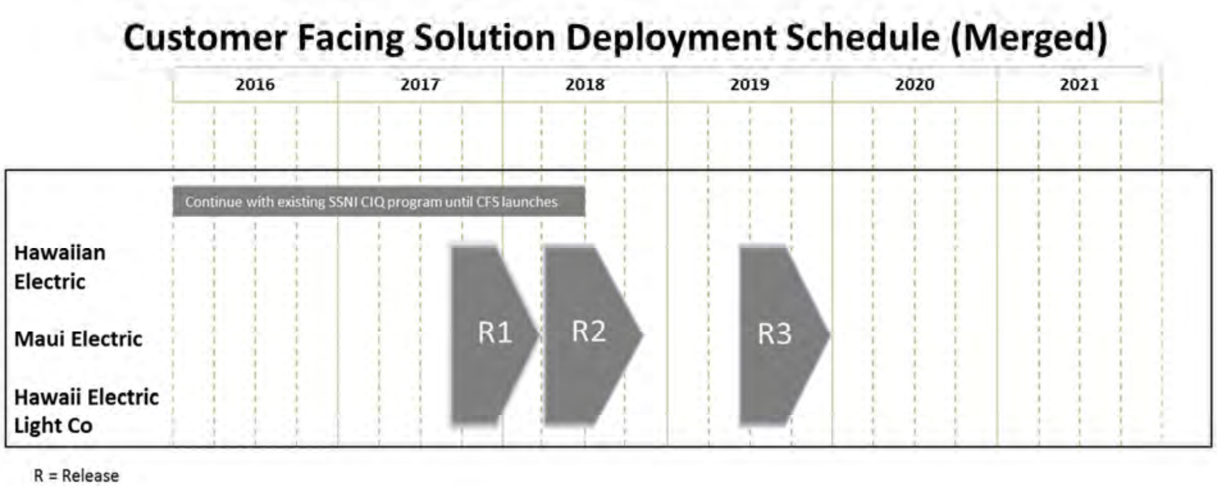

Figure 4

As further detailed in Attachment 1, the primary differences between the CFS component under the merged and unmerged scenarios relate to the timeline and the resources required for a successful implementation. It is anticipated that the merged scenario will deliver a quality product sooner, with less risk, and increased customer satisfaction. The customer energy portal will be managed as a discreet project with its own Hawaiian Electric Companies project management structure, increased resources for development, design, testing and deployment, hosting the application in the Companies' data center, beginning customer access to the customer energy portal upon certification of the customers' smart meters, and accelerating the online connect, disconnect, and transfer services for all customers.

C. CONSERVATION VOLTAGE REDUCTION

The approach and timeline for the CVR component (e.g., equipment and deployment schedule) are nearly identical under the merged and unmerged scenarios and the costs are essentially the same.

As reflected in Table 11 below, NextEra expects to acquire more favorable pricing on capacitor banks and switches for the CVR component. In addition, the merged scenario assumes utilization of FPL's EDW solution resulting in slightly lower cost of outside services. These savings are slightly offset by maintanence associated with SSNI's Sensor IQ as a result of the accelerated smart meter deployment schedule.

CVR Implementation Costs Comparison by Cost Category (Nominal $000s)			
Cost Category	Unmerged Scenario	Merged Scenario	Difference
Equipment	2,059	1,991	(68)
Hardware	71	71	-
Intercompany	-	-	-
Internal Labor	13,559	13,559	-
Maintenance	3,195	3,292	97
Miscellaneous	101	131	30
Outside Services	4,587	4,515	(72)
Software	1,559	1,559	-
Total	**25,131**	**25,118**	**(13)**
Note: Excludes AFUDC and PMO costs.			

Table 11

D. DIRECT LOAD CONTROL

The approach and timeline for the DLC component are nearly identical under the merged and unmerged scenarios. However, as shown in Table 12 below, the total DLC SGF Project cost under the merged scenario is $0.3 million lower primarily because NextEra expects to acquire more favorable pricing on the purchasing of equipment given FPL operates the largest DLC program in the country. These savings are slightly offset by higher outside services associated with the utilization of FPL's EDW and ESB solutions.

DLC Implementation Costs Comparison by Cost Category (Nominal $000s)			
Cost Category	Unmerged Scenario	Merged Scenario	Difference
Equipment	7,977	7,580	(397)
Intercompany	-	1	1
Internal Labor	308	309	1
Maintenance	855	854	(1)
Miscellaneous	38	25	(13)
Outside Services	9,215	9,293	78
Total	**18,393**	**18,062**	**(331)**
Note: Excludes AFUDC and PMO costs.			

Table 12

E. ENTERPRISE DATA WAREHOUSE

The scope of the data warehouse content and source applications will be the same under the merged and unmerged scenarios. NextEra Energy has expended a significant amount of time and effort understanding Smart Grid data, the data relationships, and how end users might want to access and utilize this data. In addition, NextEra Energy has performed numerous detailed technology evaluations amongst the big data space to determine which solutions best meet the Smart Grid data needs. As a result, a comprehensive data warehouse has been created by NextEra Energy, with the ability to process large volumes of data in an efficient manner while ensuring a robust set of controls and checks and balances are in place. The merged scenario assumes a similar approach will be used to build a data warehouse for the Companies' SGF Project.

As shown in Table 13 below, the EDW component cost under the merged scenario is $0.4 million lower than under the unmerged scenario, primarily due to lower costs for outside services and maintenance/maintenance licensing. In lieu of utilizing pre-built software to implement a EDW, the merged scenario assumes using a vendor to build a data warehouse similar to NextEra Energy's large data implementation. The selected vendor will bring experience in both data warehousing, as well as the domain experience based on their work at NextEra Energy and other utilities. This solution will result in savings in outside services, as well as longer term support and maintenance. In addition, a 5% savings is assumed based on NextEra Energy's current negotiated rates with the proposed vendor.

EDW Implementation Costs Comparison by Cost Category (Nominal $000s)			
Cost Category	Unmerged Scenario	Merged Scenario	Difference
Hardware	-	1,951	1,951
Internal Labor	1,755	1,846	91
Maintenance	4,448	3,215	(1,233)
Miscellaneous	56	155	99
Outside Services	3,352	2,087	(1,265)
Total	**9,611**	**9,254**	**(357)**
Note: Excludes AFUDC and PMO costs.			

Table 13

The EDW under the merged scenario will be housed in the Companies' data center on O'ahu as opposed to a cloud-based option hosted in a vendor data center. Additional costs are included under the merged scenario for hardware due to this difference in approach. However, the long-term support and maintenance costs are anticipated to be lower.

F. ENTERPRISE SERVICE BUS

The timeline and scope of the ESB component under the merged scenario are the same as under the unmerged scenario. However, under the merged scenario, the Companies are proposing to use NextEra Energy's existing ESB software vendor in order to leverage standardized software use across the merged companies, NextEra Energy's experience and scale pricing. As shown in Table 14 below, the total ESB component cost under the merged scenario is $2 million lower than under the unmerged scenario, with savings realized both through the initial software purchase and ongoing software maintenance as a result of current NextEra Energy pricing.[7]

ESB Implementation Costs Comparison by Cost Category (Nominal $000s)			
Cost Category	Unmerged Scenario	Merged Scenario	Difference
Hardware	505	529	24
Internal Labor	1,409	1,354	(55)
Maintenance	1,600	607	(993)
Misc.	56	153	97
Outside Services	4,408	4,586	178
Software	1,985	746	(1,239)
Total	**9,963**	**7,975**	**(1,988)**
Note: Excludes AFUDC and PMO costs.			

Table 14

[7] A separate software instance will be utilized for the Companies' implementation in Hawaiian Electric's data center on O'ahu.

As described in Attachment 1, the Companies independently selected the same ESB implementation vendor as currently used by NextEra Energy. The timeline and scope of services for the ESB implementation vendor will also remain the same as the unmerged scenario, which starts in early 2017 and ends in late 2021, including the corresponding project support during that time. Under the merged scenario, however, a 5% savings is assumed based on NextEra Energy's current negotiated rates with this vendor. These savings are reflected in the cost of outside services.

G. METER DATA MANAGEMENT SYSTEM

The scope of the MDMS component will be the same under the merged and unmerged scenarios. However, as shown in Table 15 below, the total MDMS component cost under the merged scenario is estimated to be $12.8 million lower, primarily due to lower outside services costs. Under the merged scenario, the combined companies would be able to use software that NextEra Energy developed and has been using for Smart Grid billing for several years. The replicated software approach, combined with NextEra Energy's experience is expected to result in significant savings compared to a new product installation. In addition, as described in more detail in Attachment 1, NextEra Energy's purchasing power would allow for savings in ongoing software maintenance.

MDMS Implementation Costs Comparison by Cost Category (Nominal $000s)			
Cost Category	Unmerged Scenario	Merged Scenario	Difference
Hardware	1,565	2,142	577
Intercompany	-	1,015	1,015
Internal Labor	4,985	5,119	134
Maintenance	2,873	2,031	(842)
Misc.	539	380	(159)
Outside Services	32,991	20,517	(12,474)
Software	3,702	2,607	(1,095)
Total	**46,655**	**33,811**	**(12,844)**
Note: Excludes AFUDC and PMO costs.			

Table 15

Under the merged scenario, the MDMS component would start immediately upon commencement of the SGF Project and similar to the unmerged scenario, would be carried out in two phases. Assuming Commission's approval of the accompanying application by August 2016, phase one under the merged scenario would be a 12-month project and is scheduled to deliver register read billing in the fourth quarter of 2017. Phase two under the merged scenario would also be a 12-month project, and is scheduled to provide interval billing required to facilitate dynamic pricing in fourth quarter of 2018.

In addition, the merged companies would implement a modified version of NextEra Energy's proprietary Remote Connect Service application for move-in/move-out service and collection-related actions. The Remote Connect Service application was developed by NextEra Energy to address the high priority, complexity and customer sensitivity of these transactions, as well as the heightened awareness around security. Under the merged scenario, the Companies will have the benefit of a proven, reliable and functional system which has been operational for several years rather than building a new system from scratch. The Remote Connect Service project is expected to take 12 months and would run concurrently with the last six months of MDMS phase one and the first six months of MDMS phase two.

Figure 5 below shows the deployment schedule for the MDMS during the merged SGF Project for all three utilities.

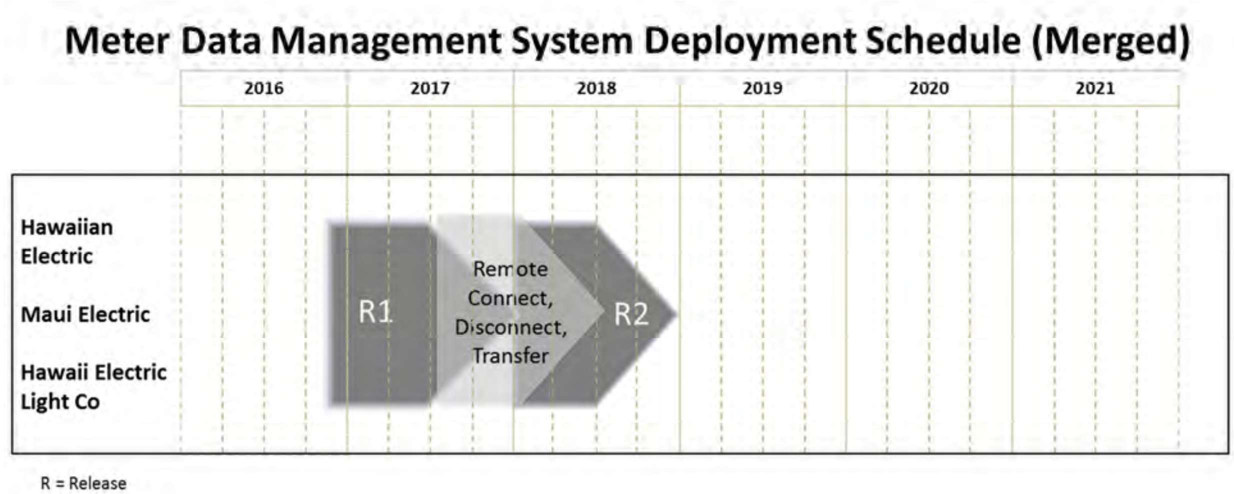

Figure 5

H. OUTAGE MANAGEMENT SYSTEM

The approach and timeline for the OMS component's implementation would be generally the same under the merged and unmerged scenarios. As shown in Table 16 below, the total OMS component cost under the merged scenario is $0.4 million less than the unmerged due to supply change savings and utilization of FPL's solution.

OMS Implementation Costs Comparison by Cost Category (Nominal $000s)			
Cost Category	Unmerged Scenario	Merged Scenario	Difference
Hardware	-	247	247
Intercompany	-	129	129
Internal Labor	2,434	2,434	-
Maintenance	1,007	315	(692)
Misc.	217	299	82
Outside Services	12,626	12,415	(211)
Software	667	667	-
Total	**16,951**	**16,506**	**(445)**
Note: Excludes AFUDC and PMO costs.			

Table 16

Under the merged scenario, lower costs for maintenance/maintenance licensing would be achieved by using the Event Processing Engine ("EPE") software developed by FPL, in lieu of SSNI's Outage Detection System ("ODS") software to perform various filtering of all "last gasp" messages to determine which messages are sustained outages that should be reported to the OMS. Similarly, integration will be required between the EPE and OMS and SAP CIS to generate the trouble tickets that feed into the OMS where outages are managed.

The merged timeline for OMS is the same as that of the unmerged scenario.

I. CUSTOMER ENGAGEMENT

The approach and timeline for the CE component is the same under the merged and unmerged scenarios. However, as shown in Table 17 below, cost of the CE component cost under the merged scenario is estimated to be $72,000 lower due to lower costs associated with miscellaneous expenses.

Customer Engagement Costs Comparison by Cost Category (Nominl $000s)			
Cost Category	Unmerged Scenario	Merged Scenario	Difference
Internal Labor	1,849	1,849	-
Miscellaneous	90	18	(72)
Outside Services	6,185	6,185	-
Total	**8,124**	**8,052**	**(72)**
Note: Excludes AFUDC and PMO costs.			

Table 17

As described in Attachment 1, the Companies' approach to customer engagement during Smart Grid deployment already reflects consultation with NextEra Energy in their plans to manage deployment risk by adopting NextEra Energy's phased communication approach.

J. PROJECT MANAGEMENT OFFICE

The PMO provides services needed to manage and maintain the overall governance, coordination and facilitation of the overall SGF Project. The costs for its services are included in the various component costs, as shown in Table 18, below.[8] The services provided under the PMO in the merged scenario, like the unmerged scenario, include internal labor and outside services contractors. In addition to these, there are intercompany services associated with the proposed Project Operational Advisory Committee. This committee consists of select NextEra Energy employees with expertise in the various individual components. Please refer to Attachment 5 for further detail breakout of PMO costs allocated by SGF Project component. The primary differences are due to the Project Operational Advisory Committee, the enhanced Change Management and PMO organization, and the System Integrator offset by the reduced project timeline for the PMO organization.

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[8] See Attachment 4 for a breakout of PMO costs by subproject and type.

Project Management Office Implementation Costs Comparison by Component (Nominal $000s)			
Cost Category	Unmerged Scenario	Merged Scenario	Difference
AMI	5,590	8,170	2,580
CFS	259	486	227
CVR	902	913	11
DLC	1,026	55	(971)
EDW	380	293	(87)
ESB	357	292	(65)
MDMS	1,258	1,794	536
OMS	474	917	443
Customer Engagement	288	321	33
Total	**10,534**	**13,241**	**2,707**

Table 18

V. MERGED COMPONENT BENEFITS

NextEra Energy will be utilizing the same benefits assumptions and calculations estimated in the unmerged scenario (see Exhibit B, Attachment 7 to the accompanying Application). These quantified benefits will be applied to the costs presented previously in this Exhibit in order to develop the estimated monthly customer impact and overall benefit-cost ratio detailed in the following section.

Additionally, these benefits were also utilized to estimate the cost recovery surcharge that is being requested as part of this Application. Details specific to the estimated surcharge are provided in Exhibit G to the accompanying Application.

VI. MERGED SGF PROJECT ECONOMIC ANALYSIS

A. CONTEXT OF THE MERGED SGF PROJECT

Much like the unmerged scenario, when viewed in isolation, the merged SGF Project does not have a positive business case. Accordingly, the same value proposition described in the Companies' *Smart Grid Strategy and Roadmap* (see Exhibit A to the accompanying Application) and addressed in the unmerged business case (see Exhibit B, Section IV.A to the accompanying Application) must be considered when evaluating the merged SGF Project as a whole.

Similar to the unmerged scenario, the merged SGF Project will serve as a platform upon which the Companies will build their Smart Grid. The components that are incrementally layered upon the Smart Grid over time will leverage existing capabilities, thereby increasing the value of the infrastructure already in place. When assessing the long-term benefits that Smart Grid will enable, an overall positive business case will allow for increased capabilities andlower costs in the long run.

B. MERGED SGF PROJECT PRESENT VALUE COSTS AND BENEFITS

Similar to the unmerged scenario, in order to evaluate the overall financial impact of the merged SGF Project on a typical residential customer, the Companies have performed an "economic analysis" that nets the twenty-year merged SGF Project costs, ongoing expenses and post-in-service costs against its Operational Benefits and Customer Benefits, taking into account the time-value of money. Unlike a traditional revenue requirements analysis, this economic analysis models Customer Benefits of the merged SGF Project as if they were Operational Benefits in order to simulate the financial impact of the meged SGF Project from a customer perspective.

As detailed in Section I.C above, the merged SGF Project is scheduled to be implemented in just over five years, at a cost of $318.2 million. Once placed in service, the Companies estimate that an additional $332.6 million of ongoing costs will need to be incurred over the anticipated 20-year asset life to support and maintain the investment. Another $51.3 million of post-in-service costs will be incurred in connection with the accelerated depreciation of the Companies' existing non-smart meters. Although these ongoing expenses and post-in-service costs are not included for purposes of the merged SGF Project cost estimate, they are included for purposes of evaluating the economics of the merged SGF Project as a stand-alone investment. Accordingly, this economic analysis assumes a total 20-year economic cost of $702.1 million in nominal dollars ($318.2 million + $332.6 million + $51.3 million), and $398.8 million on a present value basis.

As detailed in Section III of Exhibit B to the accompanying Application, the total quantified Operational Benefits and Customer Benefits of the SGF Project on a stand-alone basis over the 20-year asset life (2017-2036) is $877 million in nominal dollars, and $345 million on a present value basis. As shown in Figure 6 below, the largest drivers of the quantified benefits are anticipated to arise out of the CVR and AMI subprojects.[9]

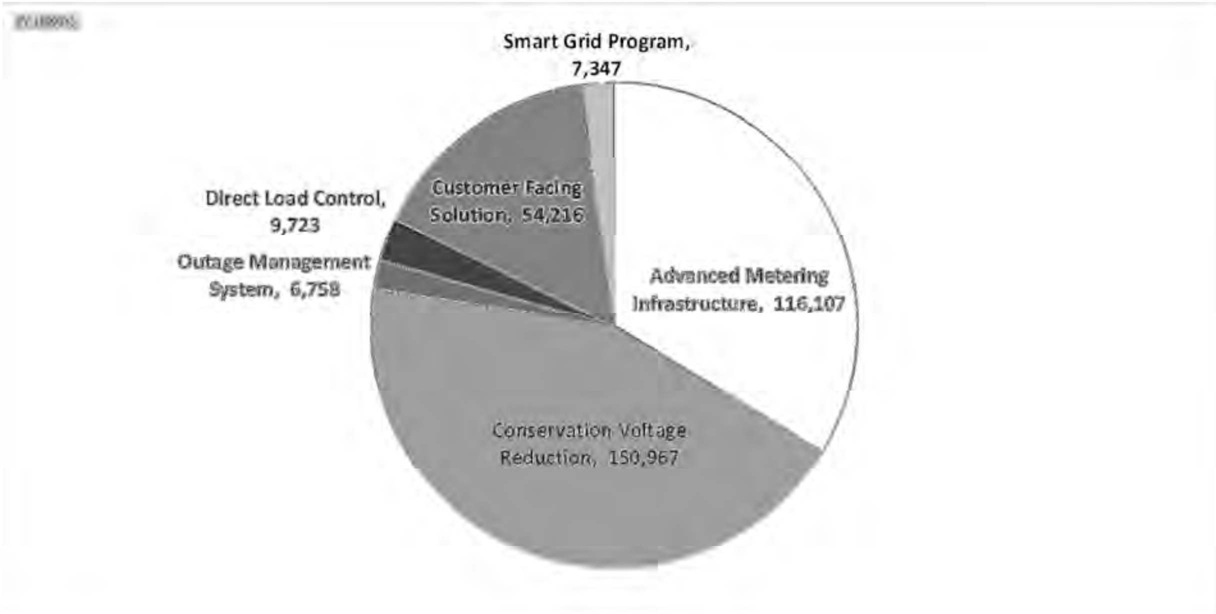

Figure 6

C. NET COSTS AND BENEFIT-TO-COST RATIO

The stand-alone present value of the merged SGF Project costs, ongoing expenses and post-in-service costs ($399 million) netted against the merged SGF Project Operational Benefits and Customer Benefits ($345 million) is negative $54 million, reflecting a benefit-to-cost ratio of 0.87. However, similar to the unmerged scenario, NextEra Energy reiterates that this present value does not take into account the monetary benefits of other initiatives that will build on the capabilities enabled by the merged SGF Project, including their DER Aggregator Contracts, DR Program Portfolio, DRMS Project, EV Time-of-use Rate Schedules, DER Time-of-use Rate Schedules, RTP Tariff, DA Project, DER Phase 1 and DER Phase 2.

D. CUSTOMER ECONOMIC IMPACT DETAILS

As shown in Figure 7 below, the economic analysis indicates that over the 20-year life of the investment, the merged SGF Project will cost (net of Operational Benefits and Customer Benefits) a typical residential customer using 500 kWh per month on average $0.03/month at Hawaiian Electric, $0.38/month at Maui Electric and $0.14/month at Hawaiʻi Electric Light, with overall cost reductions beginning in the 2028-2030 timeframe. At Hawaiian Electric, the

[9] The Companies have in the past evaluated projects using a present value of revenue requirements analysis that strictly quantifies the Operational Benefits of systems such as their proposed enterprise resource planning/enterprise asset management system (see Docket No. 2014-0170). The merged SGF Project is different from a pure business system in that many of the benefits inure directly to customers. In addition to the Operational Benefits associated with the AMI and OMS subprojects, as well as the internal labor offset, this analysis also accounts for customer benefits related to the CFS, CVR, DLC and OMS subprojects.

monthly economic impact on a typical residential customer will peak in 2018 at $1.52/month, transition into net savings in 2028 and result in peak savings of $1.74/month in 2036. At Maui Electric, the monthly economic impact on a typical residential customer will peak in 2020 at $1.67/month, transition into net savings in 2030 and result in peak savings of $1.09/month in 2034. At Hawai'i Electric Light, the monthly economic impact on a typical residential customer will peak in 2020 at $2.44/month, transition into net savings in 2029 and result in peak savings of $2.41/month in 2036.

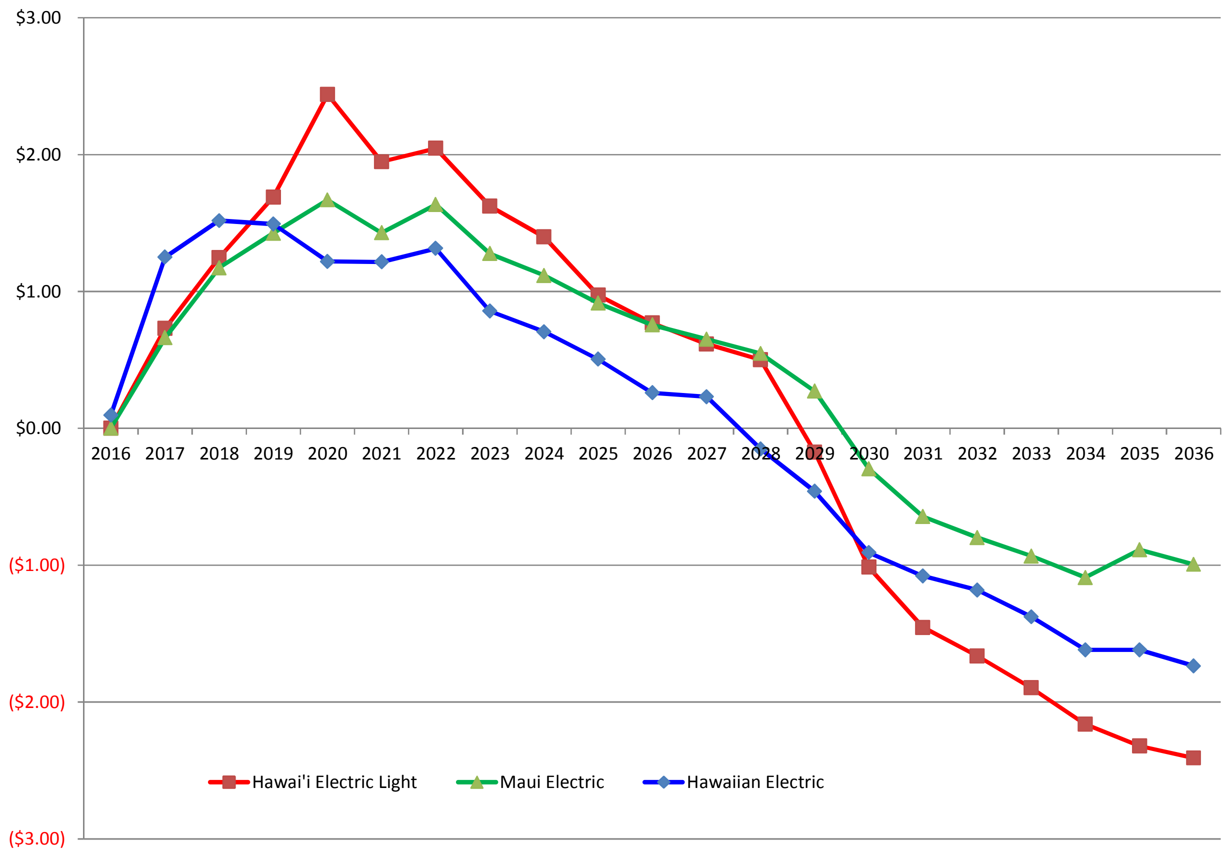

Figure 7

Additional details regarding the economic impacts illustrated above are provided in Attachment 5.

VII. <u>CONCLUSION</u>

As the Commission has recognized in its Inclinations, modern grids are a condition precedent for high penetration of distributed generation, as well as for improving customer service through enhanced outage detection and timely restoration. NextEra Energy, embracing the Commission's view, has developed the Smart Grid business case put forth in this Exhibit, a case that will enable the Companies to bring Smart Grid benefits to Hawai'i's residents faster, at a lower cost, and with lower overall risk.

Attachment 1

Smart Grid Foundation Project

Exhibit I

NextEra Energy Considerations

I. THE MERGED SCENARIO

In December 2014, NextEra Energy, Inc. ("NextEra Energy") and the Hawaiian Electric Companies ("Companies") announced a definitive agreement under which the companies agreed to combine.[1] Given NextEra Energy's expertise in Smart Grid implementation, NextEra Energy has made various subject matter experts available to the Companies to provide support in the development of the Companies' proposed Smart Grid Foundation Project ("SGF Project").

NextEra Energy has worked with the Companies, providing important benefits with its team of Smart Grid experts through sharing best practices and experience with respect to the Companies' vendor request for proposals ("RFPs"), screening process and deployment approaches. Although many benefits have already been realized through the application development process, certain benefits will only be realized if the Proposed Transaction is approved. This Attachment identifies the expected additional value and benefits NextEra Energy can provide to the Companies' SGF Project if the Proposed Transaction is approved ("Merged Scenario"). The value of NextEra Energy's experience can be maximized if the proposed merger is approved.

Hawai‘i is a frontrunner in the initial growth stage of distributed energy resources.[2] If the Proposed Transaction is approved, NextEra Energy will continue to apply its Smart Grid expertise to ensure the Companies deliver the modern grids which, as the Commission acknowledges, are a condition precedent for high penetration of distributed generation, as well as for improving customer service through enhanced outage detection and timely restoration.[3]

A. NEXTERA ENERGY'S COMMITMENT

Provided the Companies' application to deploy standard meters across all three utilities is approved in an acceptable form, NextEra Energy commits that: (1) within two years of the Commission's SGF Project approval the majority of customers will have standard meters installed, with access to an energy dashboard and remote billing within four months thereafter, or two years and four months following Commission SGF Project approval; (2) within three years and six months of Commission SGF Project approval full standard meter deployment to all customers will be complete; (3) meters will be capable of executing fixed time-of-use ("TOU") rates within two years of Commission SGF Project approval, with dynamic pricing capabilities within three years and six months of Commission SGF Project approval; and (4) requests for approval of TOU rate schedules to implement this commitment will be filed at least six months prior to meter capability and no later than three years following Commission SGF Project approval.[4]

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[1] See Application of Hawaiian Electric Companies and NextEra Energy for approval of the Proposed Change of Control ("Proposed Transaction") filed on January 29, 2015 in Docket No. 2015-0022.

[2] See Docket No. 2012-0036, Regarding Integrated Resource Planning; Decision and Order No. 32052, Exhibit A, *Commission's Inclinations on the Future of Hawaii's Electric Utilities* (April 28, 2014) [hereinafter, "Commission's Inclinations"], page 11.

[3] *Id*, page 14.

[4] For the original commitment, see Exhibit-37 to witness Eric S. Gleason's Responsive Testimony filed in Docket No. 2015-0022 on August 31, 2015, commitment 6.

As the Commission has noted in it's Inclinations, "the nature of the electric utility business is evolving rapidly in light of technical, market and public policy changes that have and will continue to occur in Hawai'i."[5] Hawai'i's electricity system is changing at an unprecedented pace and scale.[6] NextEra Energy believes that smart grid is essential to enabling the Companies to evolve and is committed to accelerating this evolution by speeding up standard meter deployment by two years.

Smart meters are the cornerstone of the Smart Grid. Accelerating standard meter deployment and the capability to support innovative rate structures is foundational to animating customer engagement in their energy use, and stimulating customer interest in alternative behaviors, rates and technologies to manage their energy use and costs, including renewable options. Delays are lost savings opportunities.

B. WHAT NEXTERA ENERGY BRINGS TO THE TABLE

NextEra Energy brings to the table a powerful combination of technological know-how and financial strength necessary for developing a modern Smart Grid, which is an important element for achieving Hawai'i's 100% Renewable Portfolio Standard ("RPS") goal by 2045. NextEra Energy will provide the Companies with daily access to the technologies, best practices and expertise of an industry leader. NextEra Energy's rate-regulated electric utility in Florida, Florida Power & Light Company ("FPL") is the third-largest electric utility in the United States serving approximately 4.8 million customer accounts across nearly half of the state of Florida and an industry leader in Smart Grid. FPL is an indirect wholly-owned subsidiary of NextEra Energy. By leveraging NextEra Energy's and FPL's knowledge and practices on Smart Grid sourcing, design, deployment and operation, it is expected that the Companies' SGF Project will be deployed faster and with lower overall costs and risks both initially and on an ongoing basis.

II. NEXTERA ENERGY'S SMART GRID EXPERIENCE

FPL helped pioneer the Smart Grid. FPL conducted extensive testing on advanced metering infrastructure ("AMI") meters in residences in 2007-2008 and created its own lab to test equipment before it was installed.[7] In 2010, FPL accelerated its Energy Smart Florida initiative with a $200 million Smart Grid Investment Grant from the U.S. Department of Energy ("DOE").[8] FPL was one of only six utilities to receive DOE funding at this level. FPL understood the promise of the Smart Grid while the technology was still in its early stages, and helped to guide development of the technical standards which were the foundation of the Smart Grid. FPL participates on the American National Standards Institute ("ANSI") C12 Standards Committees that define the physical and electrical requirements for standard meters. FPL also participates in UL 2735 (the Standard meter Safety Standard) and the completed Priority Action Plans sponsored by the National Institute of Standards and Technology ("NIST") to define

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[5] See Docket No. 2012-0036, Regarding Integrated Resource Planning; Decision and Order No. 32052, Exhibit A, *Commission's Inclinations on the Future of Hawaii's Electric Utilities* (April 28, 2014) [hereinafter, "Commission's Inclinations"], page 1.
[6] Ibid, page 6
[7] See T&D World, November 2010, available at http://tdworld.com/smart-grid/smart-spending-smart-grid.
[8] Department of Energy Award Number DE-OE0000211.

aspects of the Smart Grid, specifically Standard Meter Data Profiles and Common Semantic Model for Meter Data Tables Optimization of meters.

As FPL developed its Energy Smart Florida project, it identified needs for hardware and software applications for which solutions did not yet exist. Where solutions did not yet exist, FPL sought to invent them. The ingenuity of FPL employees resulted in three patent awards from the U.S. Patent and Trademark Office - two for solutions to provide network communications to standard meters in areas served by underground facilities and meter rooms and one for systems and methods applied to its online customer energy portal.[9] Moreover, FPL developed a system design and architecture for remote connect switches to allow secure transactions.

FPL is a recognized leader in standard meter and Smart Grid technology. FPL was awarded two electric utility industry awards from the editors of Powergrid International magazine for FPL's comprehensive Energy Smart Florida project,[10] including Smart Grid Project of the Year and Renewable Energy Integration Project of the Year, and 2014 ReliabilityOne™[11] and 2015 ReliabilityOne™[12] awards in the category of Outstanding Technology and Innovation in the U.S., awarded by PA Consulting Group.

FPL earned the Smart Grid Project of the Year award for its "Reaping the Benefits of the Smart Grid Project."[13] In March 2013, FPL completed one of the most ambitious Smart Grid projects in the country when it wrapped up an $800 million program nine months ahead of schedule. The project included the installation of 4.5 million standard meters, more than 10,000 intelligent transmission and distribution devices, and enhanced digital technology to nearly 600 substations. The new sensors and monitors installed on transformers and breakers are helping FPL determine the health of the equipment and predict potential issues before they disrupt service to customers.

The Smart Grid enables customer-sited distributed energy resources (DER) and micro grids. The Renewable Energy Integration Project of the Year recognized FPL's Smart Islanding program.[14] The DER generates power from land fill gas in Charlotte County, Florida. FPL uses an islanding system with synchrophasor technology to detect islanding conditions and trip the distributed energy resources in the stipulated time. The DER connection to an existing FPL feeder was one of the first installations of this new protection scheme, which is now FPL's standard protection package for any distributed generator larger than 3 MW, and is currently in operation at four sites.

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9 Gateway Node US 20120314341 A1, Systems and Methods for a Power Adapter US 20140227904 A1, Systems and Methods for Advanced Metering Infrastructure Customer Portal US 8645239 B2.

10 See http://www.elp.com/articles/powergrid_international/print/volume-19/issue-4/features/powergrid-international-projects-of-the-year.html.

11 See http://www.paconsulting.com/industries/energy/reliabilityone/.

12 See http://www.paconsulting.com/events/reliabilityone/.

13 See http://www.elp.com/articles/powergrid_international/print/volume-19/issue-4/features/powergrid-international-projects-of-the-year.html.

14 See http://www.prnewswire.com/news-releases/fpl-receives-two-prestigious-national-awards-for-its-state-of-the-art-smart-grid-program-242596911.html.

In addition, FPL put the Smart Grid in the hands of field restoration crews by developing mobile applications such as the Restoration Spatial View ("RSV"). RSV combines outage tickets, weather information, electrical network information, customer energy consumption and voltage, restoration crew location, meter status and more, all layered on a map view on the field crews' iPads. It incorporates features like restoration confirmation, which allows restoration crews to confirm the power status of all standard meters affected by an outage before they leave an area. This has helped FPL to resolve problems on the first visit, avoid unnecessary truck rolls, reduce repeat calls from customers and improve customer satisfaction. FPL's RSV system was awarded the Best Practices Gold Award for Outage Communications, by Chartwell in November 2014.[15]

Other pioneering work performed by FPL under its DOE grant included a pilot of near real-time energy information from the standard meter's IEEE 802.15.4[16] Home Area Network ("HAN") radio in over 450 homes. The HAN radio provided detailed, near real-time energy feedback to in-home energy displays and home energy controllers. It also provided dynamic price signals to home energy controllers and, in ten homes, smart appliances. The pilot provided FPL with valuable insight into the capabilities of HAN technology and experience with dynamic pricing.

These examples and awards demonstrate the capabilities of NextEra Energy and FPL to drive solutions that previously did not exist in the Smart Grid environment and create an advanced distribution system, which, as stated in Commission's Inclinations, is "a condition precedent for high penetration of distributed generation".[17] NextEra Energy possesses the Information Technology ("IT") and project management capabilities and experience to assist the Companies during their SGF Project's deployment to deliver the best solution on time and on budget.

C. DEPLOYMENT: BUILDING THE SMART GRID

Standard meters are the foundation of the Smart Grid, and to date FPL has deployed standard meters to over 4.8 million customers.[18] Deployment involves much more than the replacement of meters; it includes back-office systems that require extensive integration and strong logistical coordination of supply chains, vendors and project sub-activities. This type of integration involves many vendors who must be closely managed in order to deploy successfully. All utilities experience deployment hurdles that endanger the successful completion of such a complex project. FPL was no exception and hurdles arose that could never have been predicted. FPL's methodical approach to addressing these hurdles resulted in a successful deployment with

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[15] See https://www.chartwellinc.com/chartwell-announces-new-best-practices-award-category-%E2%80%93-billing-and-payment-programs/.

[16] IEEE standard 802.15.4 offers the fundamental lower network layers of a type of wireless personal area network which focuses on low-cost, low-speed ubiquitous communication between devices.

[17] See Commission's Inclinations, Page 14.

[18] See Exhibit-69 to witness Bryan J. Olnick's Responsive Testimony filed in Docket No. 2015-0022 on August 31, 2015.

minimal issues, even while installing on average 5,000 meters a day.[19] Standard meters rely on network communication devices including access points and relays, and FPL installed 11,000 such devices during its Smart Grid deployment project. This deployment was completed nine months ahead of schedule.

Stakeholder, customer, and employee engagement is essential to a successful standard meter deployment. The emerging Smart Grid transformed the way FPL operates, so FPL conducted more than 100 internal presentations reaching more than 1,500 NextEra Energy employees to explain these changes to the workforce. These presentations helped employees in communicating Smart Grid benefits to their neighbors through more than 150 outreach events to homeowner associations, local government agencies and other community organizations. FPL sent out almost 2.4 million e-mails and mailed nearly five million pieces of correspondence, including pre-notification letters and post cards informing customers when their meters would be changed, and post-activation letters which let customers know that their energy information was available on FPL's Energy Dashboard – the first tangible Smart Grid benefit FPL's customers received.

The Energy Dashboard enables customers served with standard meters to monitor their energy use by the hour, day and month, dramatically expanding their ability to manage their energy use. FPL built its Energy Dashboard in-house, with a patent issued by the U.S. Patent and Trademark Office for "Systems and Methods for Advanced Metering Infrastructure Customer Portal."[20] In 2014, customers accessed the Energy Dashboard more than three million times. FPL continues to enhance its dashboard features and improve functions. Beginning in 2014, the Energy Dashboard was enhanced to allow FPL's net energy-metering ("NEM") customers to monitor both the energy they delivered to and received from FPL. FPL customers with a TOU rate were also provided enhanced Energy Dashboard features allowing them to see their energy usage during peak and off-peak hours.

D. OPERATIONS: REAPING SMART GRID BENEFITS

Through business process improvement and change management, Smart Grid continues to enhance the value proposition to FPL customers through lower costs, faster service and increased reliability. Such benefits are not automatic and do not all come at once; they are the results of disciplined grid evolution, business process improvement and change management which identify and prioritize critical value drivers for the company and the customer and ensure that value gets delivered. In fact, all benefits are not recognizable in the beginning. FPL continues to identify new and emerging benefits through its process improvement and change management that were not identifiable early on.

FPL's Smart Grid delivered more than $30 million in operational savings in 2014 alone, savings that help FPL keep bills low for customers. The 2014 billing "read rate", which is the percentage of successful remote meter reads each month, continued to be an outstanding 99.84%. Customers also benefit from faster, more convenient service connection and disconnection when

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[19] See Exhibit-69 to witness Bryan J. Olnick's Responsive Testimony filed in Docket No. 2015-0022 on August 31, 2015.

[20] Patent number 8,645,239, issued on February 4, 2014.

opening, closing or reconnecting accounts through FPL's Remote Connect Service, which has a success rate of 99.5%. More savings come from a reduction in the number of times FPL crews have to make trips into the field to perform work – 170,000 fewer field visits through 2014.[21]

In the great majority of cases, customers with standard meters do not have to call FPL to report an outage. In 2014, FPL generated over 10,000 outage tickets before a customer reported the outage, and for about 2,000 of these incidents power was restored before any customer called to report the outage.[22] When customers do call with a power problem, FPL can quickly determine through its internally developed Event Processing Engine if the problem is with the company's system or customers' equipment, thereby facilitating and expediting both customers' and the company's ability to efficiently respond when repairs are required.

Electricity is the third most stolen product in the U.S.,[23] a crime that everyone pays for. At FPL, Smart Grid data analytics have also helped improve theft detection.

Additional 2014 achievements[24] include improved outage detection, prevention and service restoration, including:

- 500,000 avoided customer outages;
- 40,000 outage tickets supplemented with beneficial standard meter data that help expedite restoration;
- 2,000 transformers proactively replaced (smart data helps reveal potential issues with equipment so crews can replace it before it fails); and
- 400 added feeder switches and 1,200 lateral switches that help improve the system's ability to automatically restore and reroute power, decreasing the number of customers affected by longer sustained outages.

These Smart Grid benefits contribute to FPL's ability to offer its customers a typical residential 1,000-kWh bill that is approximately 30% lower than the national average, and in 2014, was the lowest in Florida among reporting utilities for the fifth year in a row.[25] This ongoing focus and investment has helped to increase reliability by more than 20% in the last five years. FPL's leadership in using Smart Grid to improve overall service reliability and reducing the customer impact from storm disruptions was detailed in the publication "Smart Grid Investments Improve Grid Reliability, Resilience, and Storm Responses" by the U.S. DOE[26] and is strong evidence of improved customer service resulting from the Smart Grid infrastructure.[27]

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[21] See Standard meter Progress Report, filed on March 20, 2015 with Florida Public Service Commission, in Docket No. 150002-EG.
[22] See Standard meter Progress Report, filed on March 20, 2015 with Florida Public Service Commission, in Docket No. 150002-EG.
[23] See http://www.forbes.com/sites/peterdetwiler/2013/04/23/electricity-theft-a-bigger-issue-than-you-think/.
[24] See Exhibit-24 to witness Bryan J. Olnick's Direct Testimony filed in Docket No. 2015-0022 on April 13, 2015.
[25] See http://newsroom.fpl.com/2015-04-16-FPL-rate-decrease-approved-by-Florida-PSC-reducing-typical-customer-bill-by-about-3-a-month.
[26] See http://energy.gov/sites/prod/files/2014/12/f19/SG-ImprovesRestoration-Nov2014.pdf.
[27] See Commission's Inclinations, Page 14.

E. EXPANSION: ONE OF THE MOST MODERN GRIDS IN AMERICA

FPL is leading the industry in grid modernization. In January 2016, United States Secretary of Energy Ernest Moniz stated "FPL really is on the cutting edge of addressing a grid for the 21st century and particularly in the area of resilience. It's really what we need." [28] Others, such as POWERGRID International, PA Consulting Group, etc. have recognized FPL for having one of the most advanced grids in the nation and one of the most comprehensive, full-scale Smart Grid deployments of its kind.[29]

FPL believes that building a Smart Grid does not end with initial deployment. FPL continues to expand its Smart Grid, adding tens of thousands of distribution automation devices to make the grid more reliable and more resilient. FPL's ongoing commitment is to build a stronger, smarter grid that customers can count on in good weather and bad. Part of the commitment to having one of the most modern grids in America includes installing thousands of automated TripSaver® devices that help decrease the number of momentary outages, or "flickers" on neighborhood power lines.

Also in 2015, FPL announced the launch of its new, high-tech Power Delivery Diagnostic Center, which is designed to leverage advanced Smart Grid technology to better manage the electric system and deliver reliable service. This diagnostic center is one of the most advanced systems in the country, providing real-time awareness of the performance of FPL's grid and enabling FPL to use predictive analytics to improve reliability for its customers.

FPL has also initiated a new project that will include the installation of communication devices, known as "smart nodes" on existing full maintenance street-lights in the Miami-Dade area. The use of this technology will reduce the need for FPL customers to call the company about street-light outages, provide FPL more efficient processes to make repairs through improved planning and scheduling, and provide the opportunity to improve reliability benefits for customers by enhancing overall network efficiency and redundancy. The planned upgrade includes 500,000 FPL-maintained street-lights. To date, 75,000 smart nodes have been installed that will be used to pilot the new infrastructure. An additional 425,000 smart nodes will be installed throughout FPL's service territory by March 2017 to complete the project.

FPL is planning to launch a Meter Enclosure Alert Service ("MEAS") in early 2016. MEAS will use standard meter data to provide residential and small business customers equipped with General Electric meters proactive detection of potential power quality issues due to issues with their meter enclosures and help ensure "end to end" power quality.

Standard meters and other Smart Grid equipment and technologies are providing real benefits to FPL's customers as well as additional and continual real-time visibility, monitoring and control information and capabilities to FPL's system operators, which are critical to enabling and facilitating the integration of DER and renewable energy into the grid. In fact, standard meters and other Smart Grid equipment and technologies serve as the platform for a more

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[28] See http://www.govtech.com/fs/US-Energy-Secretary-Backs-Florida-Smart-Power-Grid.html
[29] NextEra Energy press release, August 31, 2015, available at http://www.nexteraenergy.com/news/contents/2015/083115.shtml.

efficient integration of these resources into the grid by providing two-way communication and visibility of these bi-directional resources, where both generation and energy procurement is taking place.

A fully deployed Smart Grid is better able to monitor and respond to changes in power flow and voltages produced by distributed and intermittent sources. Smart Grid's communications and monitoring capabilities provides insight at the distribution system level which have previously only been available at the transmission level. Consistent with the Commission's Inclinations[30], FPL views such insight into the state of the distribution system as foundational to understanding the immediate impact of intermittent sources on the distribution system, and eventually enabling emerging technologies and applications such as Smart Grid interaction with smart inverters.

III. MERGED SMART GRID APPROACH

First-hand experience and insight into the challenges and opportunities of a large scale Smart Grid deployment and integration are invaluable. FPL's recent, successful Smart Grid experience will be available to the Companies as members of the NextEra Energy family and can be leveraged to accelerate the deployment of the Companies' SGF Project while reducing cost and risk. One of the primary benefits FPL has to offer is that FPL has a strong understanding of the requirements, challenges and solutions that are available to help make the Companies' Smart Grid initiative successful. A Smart Grid deployment is a complex IT initiative involving multiple vendors, new systems with many interdependencies and integration with existing systems and processes. A team of FPL Smart Grid experts, experienced with these technologies and their providers, worked with the Companies throughout 2015 on administering RFPs, statements of work, and planning for a proven, phased approach to deployment. During the exchange, FPL experts have shared extensively from their experience in Smart Grid deployment and lessons learned, conducted detailed reviews of RFPs, provided input on potential vendor solutions, and identified existing NextEra Energy systems and skill sets which could be extended to the Companies to help manage cost, time and deployment risk. These exchanges were instrumental to defining the merged Smart Grid approach presented in this application.

Sub-sections A through F below provide details about the benefits already adopted and the benefits to be achieved in the areas of standard meter deployment, procurement and supply chain management, financial leverage, systems integration and business process change, customer engagement, and demand response ("DR") (time-variant rates and direct load control). Attachment 1 to accompanying Exhibit provides a summary of the benefits already adopted and to be achieved under a Merged Scenario. The costs associated with the benefits described in sub-sections A through F below are included in the accompanying Exhibit.

A. STANDARD METER DEPLOYMENT

When it comes to reducing deployment risk, there is no substitute for experience. The value of FPL's experience in deploying and integrating a large-scale Smart Grid initiative is

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[30] See Commission's Inclinations, Page 13.

important. Absent this experience, the Companies will need to spend time, effort and financial resources learning the lessons NextEra Energy has already learned and duplicating work NextEra Energy has already completed. This could be said about any utility taking on a full-scale Smart Grid implementation for the first time.

- Benefits already adopted: The Companies' planned approach to standard meter deployment already reflects consultation with NextEra Energy in their plans to manage deployment risk by adopting NextEra Energy's proven, phased approach to the installation of standard meters by starting on one island and expanding to two more islands, then completing the remaining two islands. The phased approach will help ensure successful installation of standard meters in Hawai'i. Successful deployment of standard meters involves stringent planning, including the development of a work plan and processes, ensuring sufficient inventory, and conveying information to customers. The phased approach provides the best opportunity to test and stabilize processes, equipment and vendor installation.

- Additional benefits to be achieved under the Merged Scenario: NextEra Energy will add value by:

    - Accelerating standard meter deployment by two years, saving money and delivering customer benefits sooner. Provided the Companies' application to deploy standard meters across all three utilities is approved in an acceptable form, NextEra Energy has committed that full standard meter deployment to all customers will be complete two years before the in-service date in an un-Merged Scenario;

    - Reduction in standard meter deployment costs due to shortening the deployment by two years;

    - Providing deployment guidance to the Companies through NextEra Energy Advisory Committees composed of seasoned experts in Smart Grid deployment and technology. Guidance will be provided in a number of areas, including, but not limited to:

        - Network Communications - NextEra Energy has developed an approach which maximizes the power of the meter mesh network and avoids over-investing in expensive network communication devices. NextEra Energy's approach was valuable in Florida's flat terrain, and may prove to be valuable in Hawai'i's varied terrain;

        - Vendor Management is essential to the timely and cost-efficient delivery of high-volume, high-velocity deployments, and assures minimization of warehouse space and optimal delivery of materials to workers. Any break in the supply chain can halt deployment and idle workers. NextEra Energy has extensive experience in managing vendors in the Smart Grid space;

- Exception Handling is the ability to recognize, record, and resolve situations where a meter cannot be installed. It is difficult to predict the variety of situations that may be encountered when changing every meter within a service territory, and a robust exception handling process is essential for timely completion and supports a deployment which is *complete*; and

- Transitioning to Regular Business involves optimization and certifying Smart Grid sections to be *ready for business*. NextEra Energy's proven approach involves a battery of tests to assure the Smart Grid – and its associated business processes – are ready to serve customers seamlessly. Optimization involves the performance assessment of a grid section's redundancy and resiliency, testing of the overhead and meter mesh networks, and verification of meter read rates. Only after a grid section is tested and verified to be capable of operation is it certified to be ready for business use.

B. PROCUREMENT AND SUPPLY CHAIN MANAGEMENT

The Companies' SGF Project can benefit from access to NextEra Energy's Integrated Supply Chain ("ISC") group and its experience with the sourcing, contracting, contract management, and close-out of major, successful, Smart Grid projects. Benefits to be achieved under the Merged Scenario include:

- Access to its multi-billion dollar purchasing power, with consequent benefits in pricing, scheduling, and supplier attention. The ISC group enables NextEra Energy to consolidate vendors and achieve volume discounts. NextEra Energy's position provides top-tier customer status with industry-leading providers and manufacturers. Significant near-term cost reductions are expected from the benefit of joint procurement and supply chain management. NextEra Energy believes it should be able to achieve savings of about 5% of total procurement costs. The Merged Scenario reflects up to 5% reduction in rates depending on the project and vendor. Due to legal restrictions, NextEra Energy is prohibited from negotiating specific prices with the vendors selected by the Companies prior to closing of the merger;[31]

- Access to a large, dedicated in-house legal staff with extensive knowledge of commercial contracting, including mitigating specialized and rare commercial and technical risks;

- Contract extensions - NextEra Energy has identified existing contracts with key Smart Grid suppliers which may be extended to NextEra Energy affiliates, including the Hawaiian Electric Companies. These contract extensions will provide the

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[31] See Exhibit-50 to witness John J. Reed's Responsive Testimony filed in Docket No. 2015-0022 on August 31, 2015

Companies with immediate time and cost savings by avoiding the need to negotiate contracts. They will also provide the Companies with access to scale pricing and top-tier vendor attention for major Smart Grid systems; and

- Future contract negotiations by NextEra Energy's ISC, with benefits accruing to the Companies and their customers. This approach may bring savings to other major Smart Grid systems including, but not limited to, distribution automation devices, such as TripSaver switches.

C. FINANCIAL LEVERAGE

The Companies' SGF Project has substantial capital requirements and can benefit from the Proposed Transaction and NextEra Energy's financial strength. Benefits to be achieved under the Merged Scenario include:

- Improved financial status of the Companies as a result of NextEra Energy's strong capital resources and financial capabilities. This in turn will provide a meaningful benefit for the Companies in addressing their ongoing needs for liquidity, credit and capital as the Companies look to invest in Hawaiʻi's clean energy future, including Smart Grid; and

- Access to long-term financing in the public debt and equity markets - NextEra Energy currently has the largest corporate credit facility in the industry, with robust liquidity that is currently comprised of approximately $9.2 billion of credit commitments from 68 banks.[32] Through its extensive resources, NextEra Energy is committed to supporting the Companies with plans to subsequently access the capital markets to raise long-term financing as appropriate and realize the benefits of the volume cost discounts brought to bear by NextEra Energy and its banking relationships.

D. SYSTEMS INTEGRATION AND BUSINESS PROCESS CHANGE

Systems Integration is the beating heart of the Smart Grid. Standard meters produce unprecedented amounts of data. To be of value, this data must be efficiently collected, stored and served, in real time, to business unit systems for interpretation. Successful systems integration requires a good understanding of the business processes that have to change as a result of Smart Grid implementation.

- Benefits already adopted: The Companies' approach to Business Process Change and Systems Integration has since been incrementally enhanced via expert consultation with NextEra Energy in their plans to realize Smart Grid benefits by:
    - Enhancing the Business Process Improvement ("BPI") element to the Companies' SGF Project to ensure Smart Grid transforms the overall

[32] See pages 25-26 of the Application of Hawaiian Electric Companies and NextEra Energy for approval of the Proposed Change of Control filed on January 29, 2015 in Docket No. 2015-0022.

customer experience by identifying processes that will change as a result of Smart Grid functionality and creating a detailed, prioritized, process improvement roadmap;

- Improving the enhanced ESB strategy that will provide flexible and adaptable interfacing between systems and reduce coding and testing costs as systems and business processes evolve. While the Companies have selected a different software product than that used by NextEra Energy, they have independently selected NextEra Energy's current ESB vendor; and

- Improving the EDW approach which is suitable for storing and analyzing the unprecedented amounts of data produced by Smart Grid, based on lessons learned by NextEra Energy.

- Additional benefits to be achieved under the Merged Scenario: NextEra Energy will help the Companies further reduce risk associated with the very large System Integration initiative by:

  - Optimizing the sourcing strategy and consolidating accountability under a System Integrator. The System Integrator role reduces delivery risk by creating clear accountability for ensuring that individual projects stay on track and successfully support the business process changes that deliver value to the Companies and their customers;

  - Providing a proven reusable ESB development framework, already familiar to the selected vendor, will reduce the risk of this task. The enhanced ESB implementation is critical, as it must be operational before standard meter installation begins;

  - Accelerating MDMS deployment by five months, and reducing MDMS risk and costs, because in a Merged Scenario the Companies will be implementing the same software product already in use at NextEra Energy;

  - Reducing risk associated with the EDW model. EDW is a system used for reporting and data analysis. NextEra Energy proposes to implement a proven big data technology used by NextEra Energy. NextEra Energy's EDW model, while not completely reusable by the Hawaiian Electric Companies, may serve as the basis for the Companies' model, reducing implementation risk;

  - Supporting the development of a Standard meter Diagnostic Center. FPL spent over three years developing its state-of-the-art center, and can share its diagnostic tools, processes and skills to save the Companies years of development time and help ensure Hawai‘i's Smart Grid remains reliable. FPL's Standard meter Diagnostic Center is responsible for proactively monitoring and managing the network, quickly identifying and accurately resolving potential network communications issues – before they become problems; and

- Offering enhanced IT Support. NextEra Energy has a proven track record of managing large, concurrent, multi-year IT projects to success. The Companies will benefit from NextEra Energy's in-house expertise on shared IT products as well as its skilled management of the global support resources necessary to keep a Smart Grid running 24/7. Under the Merged Scenario, NextEra Energy and the Companies will share several key IT products, including the ESB and MDMS, discussed above. NextEra Energy operates these products today, and has developed in-depth institutional knowledge of them. NextEra Energy's product expertise will be an asset to the Companies as they plan, implement and operate these complex systems. These shared software products are regularly updated with new releases. Each new release must be carefully and thoroughly tested prior to being put into production. NextEra Energy will test and operate these new releases before the Companies, sparing them this task.

E. CUSTOMER ENGAGEMENT

Customer Engagement is an essential part of the Smart Grid deployment. Customer engagement includes initial acceptance of standard meters and longer-term adoption of their benefits. NextEra Energy's extensive deployment provided an opportunity to understand the variety of ways customers react to standard meters - from enthusiasm to outright rejection. In addition, a customer's digital relationship with its utility depends on how all the customer's needs are met digitally, beginning with opening an account. It needs to be easy to check balances, pay online, report outages and even view restoration status. Interfaces must be responsive to a growing number of mobile devices, and have content that is accessible to a wider range of people with disabilities.[33] NextEra Energy has built a team focused on understanding and building an integrated, effective, accessible, end-to-end digital customer journey. Their work, delivering an improved experience on FPL.com, received a top ten ranking in the "E Source 2015 Review of 102 North American Electric and Gas Company Residential Websites." From mobile-first interface optimization, to Human Factors International-certified usability analysts to social media, NextEra Energy can reduce the Companies' total digital risk by helping them to build a long-term digital customer base that makes the Online customer energy portal part of its digital life.

- Benefits already adopted: The Companies' approach to customer engagement during Smart Grid deployment already reflects extensive consultation with NextEra Energy in their plans to manage deployment risk by:

[33] See the Web Content Accessibility Guidelines available at http://www.w3.org/TR/WCAG20/. NextEra Energy's FPL.com is almost fully Grade A compliant.

- Providing the Companies with guidance and direct support from NextEra Energy's phased communication approach and recent, large-scale experience deploying standard meters. Prior to the merger agreement, NextEra Energy was one of the Smart Grid programs that the Companies studied as it developed its plans for customer engagement, which align closely with the phased communication approach. The phased approach includes plans for providing individual customers with the proper advance notice of the new meter, communication at replacement and communication upon meter activation, all conducted in a supportive context of informed media, government officials, first responders and community stakeholders. The approach includes metrics and evaluations which allow the Companies to benchmark the results of its communication efforts.

- Refining budgets to support customer engagement through traditional media, social media and personal outreach;

- Identifying the need to add a resource to manage customer education end-to-end;

- Planning ongoing research and metrics to the Companies' existing capabilities to assess the success of engagement efforts and guide their refinement;

- Identifying the need to add resources for personnel skilled in customer advocacy to complement the Companies' resources to assist with resolving concerns about standard meter risks and help manage installation exceptions;

- Providing plans for conducting in-depth consumer usability studies consistent with Human Factors International-certified usability analysis to help ensure the best user experience; and

- Jointly developing a robust online functional blueprint to ensure a consistent customer experience, whether customers choose to do business by phone or online.

- Additional benefits to be achieved under the Merged Scenario:

  - Providing the Companies with ongoing guidance and support through closer collaboration, allowing the Companies to further benefit from NextEra Energy's experience. The Companies will have the full benefit of NextEra Energy's phased communication approach, including lessons-learned, plans, fact sheets, media and government resources, as well as access to its communications executives' experience from managing large-scale deployments. NextEra Energy and the Companies will adjust the above tools to reflect the Hawai'i culture and to ensure that the messages are aligned with the communities served.

- Consistent with the guidelines in Commission's Inclinations, NextEra Energy will focus on "delivering immediate value and benefits to customers"[34] and will commit increased resources to the Online customer energy portal to further reduce deployment risk and increase the likelihood that customers will become repeat users of the portal by:
  - Managing the Online customer energy portal as a discreet project with its own project management structure. The Online customer energy portal is the first tangible experience most customers have with the Smart Grid – seeing their energy usage – in detail – before they receive a bill. NextEra Energy has gained experience in understanding how customers interact with this product, and how to make this experience more intuitive, informative, and one that customers will continue to engage with. Additionally, NextEra Energy has learned how the portal needs of residential and business customers differ. Regardless of which product the Companies select, that product will depend on fast, efficient data flow to provide a responsive user experience. NextEra Energy will collaborate with the Companies to enhance the customer experience by sharing proven systems and methods for serving data to the Companies' portal;
  - Increasing resourcing for development, design, testing and deployment;
  - Hosting the application in the Companies' data center, consistent with NextEra Energy data hosting policies;
  - Beginning customer access to the Online customer energy portal upon certification of the customer's standard meter, ensuring that the customer's first experience with the Online customer energy portal is rich and informative, and increasing the likelihood that the customer will use the Online customer energy portal again in the future; and
  - Accelerating the introduction of online Connect and Transfer services by approximately one year. These new online services will be mobile-friendly and integrate with the standard meter's automated connect switch.

F. DEMAND RESPONSE: TIME-VARIANT RATES AND DIRECT LOAD CONTROL

DR programs offer customers voluntary energy options. Traditionally, such programs have used pricing, load management, customer-sited generation and energy storage to help manage grid efficiency. In the future, they are expected to also support the expansion of renewable energy by helping to match demand to intermittent sources through peak shaving and load shifting.

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[34] See Commission's Inclinations, Page 14.

FPL has extensive experience with cost-effective demand response. FPL has successfully engaged approximately 800,000 or approximately 20% of its residential customers in its load management program, an option which rewards customers for serving as a substitute for approximately 1,000 MW of peak generation. FPL's Commercial / Industrial load control customers provide an additional ~800 MW of peak reduction, in many cases enabled by customer-sited back-up generators which engage upon utility-initiated control signals. Customer-sited PV is beginning to support participation in FPL's peak load curtailment program (Port St. Lucie Civic Center ~200 kW, City of Plantation ~20 kW). FPL has supported large scale, customer-sited energy storage systems since 1991, and by combining customer-sited thermal energy storage with TOU rates, FPL has incented the shifting of 120 MW of peak load.

FPL is also gaining experience in managing electric vehicle charging networks and operates a network of 51 dual-handle workplace charging stations for the use of employees and its corporate fleet of over 150 plug-in electric vehicles.

1. Time-Variant Rates

NextEra Energy recognizes that time variant pricing programs are important for achievement of Hawai‘i's 100% RPS goal. One of the guidelines in the Commission's Inclinations is to support "rapid adoption of innovative rate structures"[35] and as a result NextEra Energy will accelerate the time-variant rate capabilities under the Merged Scenario:

- Provided the Companies' application to deploy standard meters across all three utilities is approved in an acceptable form, NextEra Energy has committed that: (1) within two years of Commission SGF Project approval the majority of customers will have standard meters installed, with access to energy dashboard and remote billing within four months thereafter, or two years and four months following Commission SGF Project approval; (2) within three years and six months of Commission SGF Project approval full standard meter deployment to all customers will be complete; (3) meters will be capable of executing fixed TOU rates within two years of Commission SGF Project approval, with dynamic pricing capabilities within three years and six months of Commission SGF Project approval; and (4) requests for approval of TOU rate schedules to implement this commitment will be filed at least six months prior to meter capability and no later than three years following Commission SGF Project approval;

- FPL has offered dynamic pricing tools such as real-time pricing in the past and piloted critical peak pricing, including sending price signals through standard meters to in-home controllers. FPL has experience in the costs, benefits and customer reaction to such programs.

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[35] See Commission's Inclinations, Page 15.

2. Direct Load Control

FPL currently has approximately 1 million load control devices deployed in Florida and is evaluating the performance and benefits associated with converting to Smart Grid-enabled load control.

- Benefits already adopted: The Companies' planned approach to direct load control already reflects consultation with NextEra Energy in their plans to manage cost and deployment risk by:
  - Reducing the time to deploy direct load control to two years from five years; and
  - Deferring deployment of load control to a later phase of the SGF Project to focus on successful meter deployment first.
- Additional benefits to be achieved under the Merged Scenario:
  - NextEra Energy's experience operating large-scale, cost-effective residential DR programs since the mid-1980s and business DR programs since 1990 will be valuable in assisting the Companies in determining the best solutions for Hawai'i and enabling customer-sited distributed energy resources, consistent with the guidelines in the Commission's Inclinations.[36] NextEra Energy recognizes that a different portfolio of DR programs may be needed as compared to those in Florida due to energy load and capacity differences.
  - NextEra Energy could potentially reduce cost through scale purchasing, should NextEra Energy decide to update its direct load control technology using the same vendor selected by the Companies.

NextEra Energy believes that Smart Grid data can be transformational in enabling and enhancing customer-facing programs. Smart Grid data, shared in a manner consistent with cyber security and data privacy policies, can help authorized third parties to design and enable energy conservation and load-shifting programs, identify customers likely to benefit from such programs and quantify program results.

IV. CONCLUSION

Standard meters and other Smart Grid equipment and technologies serve as the platform for a more efficient integration of renewable resources into the grid by providing two-way communication where both generation and energy procurement is taking place. Combining the Companies' ability to leverage FPL's knowledge and experience with Smart Grid deployment and grid modernization with NextEra Energy's commitment to the attainment of Hawai'i's 100%

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[36] *Ibid*

RPS[37], can only enhance the Hawaiian Electric Companies' objective of modernizing their grids so as to support the maximum level of cost-effective renewable resources.

As described in the accompanying Exhibit, the Companies have already leveraged certain best practices from NextEra Energy. These benefits, although already adopted to a large degree by the Companies, can be maximized through the continuing assistance that will be provided when implemented as members of the NextEra Energy family. The necessary skills, knowledge, resources and experience will be available to the Companies, which, combined with NextEra Energy's vested interest in and commitment to the Hawaiian Electric Companies, can only enhance the Companies' opportunity for deploying their SGF Project with considerably lower overall risk,[38] effectively, efficiently, and in a way that will best serve their customers.

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[37] See Exhibit-37 to witness Eric S. Gleason's Responsive Testimony filed in Docket No. 2015-0022 on August 31, 2015, commitment 5

[38] See Section II.B.2 of the accompanying Exhibit for a detailed description of the Overall Risk Management in the Merged Scenario

Appendix A

Smart Grid Foundation Project

Exhibit I

Attachment 1

Merged Benefits Summary

NEXTERA ENERGY'S MERGED BENEFITS SUMMARY

Area	Benefits:	
	Already adopted [39]	To be achieved under a Merged Scenario
Standard meter Deployment	• Phased approach to the installation of standard meters by starting on one island and expanding to two more islands, then completing the remaining two islands.	• Accelerate the standard meter deployment by two years. • Reduction in standard meter deployment costs due to shortening the deployment by two years. • Deployment guidance through NextEra Energy Advisory Committees composed of seasoned experts in Smart Grid deployment and technology.
Procurement and Supply Chain Management		• Benefits in pricing, scheduling, and supplier attention due to access to multi-billion dollar purchasing power. • Access to a large, dedicated in-house legal staff with extensive knowledge of commercial contracting. • Extend existing contracts with key Smart Grid suppliers to the Companies, which will result in immediate time and cost savings by avoiding the need to negotiate contracts and provide the Companies with access to scale pricing and top-tier vendor attention for major Smart Grid systems. • Negotiate future contracts by NextEra Energy's Integrated Supply Chain group.
Financial Leverage		• Improved financial status of the Companies as a result of NextEra Energy's strong capital resources and financial capabilities, which will provide a meaningful benefit for the Companies in addressing their ongoing needs for liquidity, credit and capital as they look to invest in Smart Grid. • Access to long-term financing in the public debt and equity markets, which will better support the Companies' plans to subsequently access the capital markets to raise long-term financing as appropriate and realize the benefits of the

[39] These benefits, although realized/adopted under the Un-Merged Scenario, can be maximized when implemented under the Merged Scenario.

Area	Benefits:	
	Already adopted [39]	To be achieved under a Merged Scenario
		volume cost discounts brought to bear by NextEra Energy and its banking relationships.
Systems Integration	• Improve the enhanced Enterprise Service Bus ("ESB") strategy that will provide flexible and adaptable interfacing between systems and reduce coding and testing costs as systems and business processes evolve. • Improve the Enterprise Data Warehouse ("EDW") approach which is suitable for storing and analyzing the unprecedented amounts of data produced by Smart Grid, based on lessons learned by NextEra Energy.	• Consolidate accountability under a System Integrator to reduce delivery risk by creating clear accountability for ensuring individual projects stay on track and successfully support the business process changes. • Provide a proven reusable ESB development framework, already familiar to the selected implementation vendor, which will reduce the risk of this task. • Accelerate Meter Data Management Systems ("MDMS") deployment by five months, and reduce MDMS risk and costs by implementing the same software product already used by NextEra Energy. • Reduce risk associated with the enhanced EDW model by implementing a proven big data technology used by NextEra Energy. • Support the development of a Standard meter Diagnostic Center by sharing diagnostic tools, processes and skills which can save the Companies years of development time. • Offer enhanced Information Technology Support through in-house expertise on shared IT products and skilled management of the global support resources.
Business Process Change	• Enhance the BPI element to ensure Smart Grid transforms the overall customer experience by identifying processes that will change as a result of Smart Grid functionality and creating a detailed, prioritized, process improvement roadmap.	
Customer Engagement	• Provide guidance and direct support from NextEra Energy's phased communication approach and recent, large-scale	• Provide the Companies with ongoing guidance and support through closer collaboration, allowing the Companies to further benefit from NextEra Energy's

Area	Benefits:	
	Already adopted [39]	To be achieved under a Merged Scenario
	experience deploying standard meters. • Refine budgets to support customer engagement through traditional media, social media and personal outreach. • Identify the need to add a resource to manage customer education end-to-end. • Plan ongoing research and metrics to the Companies' existing capabilities to assess the success of engagement efforts and guide their refinement. • Identify the need to add resources for personnel skilled in customer advocacy to complement the Companies' resources to assist with resolving concerns about standard meter risks and help manage installation exceptions. • Provide plans for conducting in-depth consumer usability studies consistent with Human Factors International-certified usability analysis to help ensure the best user experience. • Jointly develop a robust online functional blueprint to ensure a consistent customer experience.	experience. • Manage the Online customer energy portal as a discreet project with its own project management structure. • Increase resourcing for development, design, testing and deployment. • Host the application in the Companies' data center, consistent with NextEra Energy data hosting policies. • Begin customer access to the Online customer energy portal upon certification of the customer's standard meter. • Accelerate the introduction of online Connect and Transfer services by approximately one year.
<u>Time-Variant Rates</u>		• Provided the Companies' application to deploy standard meters across all three utilities is approved in an acceptable form, standard meters will be capable of executing fixed TOU rates within 2 years of Commission approval, with dynamic pricing capabilities within 3 years and 6 months of Commission approval. • File requests for approval of time-of-use rate schedules to implement this commitment at least six months prior to meter capability and no later than 3 years following Commission approval.
<u>Direct Load</u>	• Reduce the time to deploy direct	• Access to NextEra Energy's experience

Area	Benefits:	
	Already adopted [39]	To be achieved under a Merged Scenario
Control	load control to two years from five years. • Defer deployment of load control to later phase of the SGF Project to focus on successful meter deployment first.	operating large-scale, cost-effective Residential DR programs since the mid-1980s and Business DR programs since 1990. • Reduce cost through scale purchasing, should NextEra Energy decide to update its direct load control technology using the same vendor selected by the Companies.

Attachment 2

Smart Grid Foundation Projet

Exhibit I

Merged Cost Components by Company

MERGED COST COMPONENTS BY COMPANY

The merged scenario of the Companies ("Companies") Smart Grid Foundation Project ("SGF Project") followed the same allocation of costs per Company methodology that was used under the unmerged scenario (see Attachment 2 of Exhibit B to the accompanying Application). These breakouts presented herein align with the cost allocation assumptions for each Company provided as part of Section IV of the accompanying Exhibit.

Sections I through III show a breakout for each component's costs, by year, accounting treatment and Company, throughout the merged Smart Grid Foundation Project's ("SGF Project") implementation. Costs provided here are total costs for each component, inclusive of equipment, hardware, internal labor, maintenance, miscellaneous, outside services, software and AFUDC, where applicable.

I. HAWAIIAN ELECTRIC MERGED SGF PROJECT IMPLEMENTATION COSTS

The total nominal cost for the merged SGF Project's implementation specific to Hawaiian Electric is $224.3 million, or approximately 70% of the total merged SGF Project's implementation costs, as shown in Table 1, below. The capital, deferred and expense costs are broken out in accordance with the Companies' existing accounting and ratemaking treatment policies (see Exhibit F to the accompanying Application), and are aligned with the breakouts described in Attachment 2 of Exhibit B to the accompanying Application.

Hawaiian Electric Merged SGF Project Implementation Costs by Accounting Treatment and Year (Nominal $000s)							
Accounting Treatment	2016	2017	2018	2019	2020	2021	Total
Capital	3,575	65,627	37,112	6,572	9,856	10,197	132,940
Deferred	-	25,952	20,254	4,747	1,385	1,311	53,651
Expense	977	11,064	8,604	7,358	4,344	5,313	37,660
Total	**4,552**	**102,644**	**65,970**	**18,678**	**15,587**	**16,821**	**224,251**

Table 1

Table 2, below, shows these costs by component and year for Hawaiian Electric during the merged SGF Project's implementation.

Hawaiian Electric Merged SGF Project Implementation Costs by Component and Year (Nominal $000s)							
Component	2016	2017	2018	2019	2020	2021	Total
AMI	899	68,681	35,868	7,686	1,711	1,820	116,665
CFS	25	1,967	5,139	3,216	-	-	10,347
CVR	-	5,666	4,987	1,241	1,623	2,201	15,717
DLC	-	192	852	228	8,659	8,212	18,143
EDW	-	2,485	1,539	1,691	1,525	2,433	9,674
ESB	311	2,709	1,284	1,28	1,246	1,555	8,432
MDMS	3,317	18,088	14,350	1,084	-	-	36,840
OMS	1	224	615	971	3	-	1,814
CE	-	2,632	1,335	1,232	821	600	6,620
Total	**4,552**	**102,644**	**65,970**	**18,678**	**15,587**	**16,821**	**224,251**

Table 2

II. HAWAI‘I ELECTRIC LIGHT MERGED SGF PROJECT IMPLEMENTATION COSTS

The total nominal cost for the merged SGF Project's implementation for Hawai‘i Electric Light is $51.2 million, or approximately 16% of the total merged SGF Project's implementation costs, as shown in Table 3 below. The capital, deferred and expense costs are broken out in accordance with the Companies' existing accounting and ratemaking treatment policies (see Exhibit F to the accompanying Application), and are aligned with the breakouts described in Attachment 2 of Exhibit B to the accompanying Application.

Hawai‘i Electric Light Merged SGF Project Implementation Costs by Accounting Treatment and Year (Nominal $000s)							
Accounting Treatment	2016	2017	2018	2019	2020	2021	Total
Capital	31	2,304	17,226	17,485	562	831	38,441
Deferred	-	-	1,603	3,405	-	-	5,009
Expense	2	1,409	2,163	2,076	1,087	971	7,709
Total	**33**	**3,713**	**20,993**	**22,967**	**1,650**	**1,802**	**51,159**

Table 3

Table 4 provides these same costs by component and year.

Hawai'i Electric Light Merged SGF Project Implementation Costs by Component and Year (Nominal $000s)							
Component	2016	2017	2018	2019	2020	2021	Total
AMI	30	2,463	15,658	16,514	719	663	36,047
CFS	-	-	-	-	-	-	-
CVR	-	221	2,283	1,832	742	1,010	6,087
DLC	-	-	-	-	-	-	-
EDW	-	-	-	-	-	-	-
ESB	-	-	-	-	-	-	-
MDMS	-	-	-	-	-	-	-
OMS	3	1,008	2,766	4,357	13	-	8,147
CE	-	22	286	264	176	129	877
Total	**33**	**3,713**	**20,993**	**22,967**	**1,650**	**1,802**	**51,159**

Table 4

III. MAUI ELECTRIC MERGED SGF PROJECT IMPLEMENTATION COSTS

The total nominal cost for Maui Electric during the merged SGF Project's implementation is $42.8 million, or approximately 13% of the total implementation costs associated with the merged SGF Project. Table 5, below, shows these costs broken out by accounting treatment and year, while Table 6 provides these costs by component and year. The capital, deferred and expense costs are broken out in accordance with the Companies' existing accounting and ratemaking treatment policies (see Exhibit F to the accompanying Application), and are aligned with the breakouts described in Attachment 2 of Exhibit B to the accompanying Application.

Maui Electric Merged SGF Project Implementation Costs by Accounting Treatment and Year (Nominal $000s)							
Accounting Treatment	2016	2017	2018	2019	2020	2021	Total
Capital	31	2,598	18,872	7,438	594	785	30,318
Deferred	-	-	1,599	3,386	-	-	4,985
Expense	2	1,438	2,082	1,841	1,130	1,015	7,508
Total	**33**	**4,036**	**22,552**	**12,666**	**1,724**	**1,800**	**42,811**

Table 5

Maui Electric Merged SGF Project Implementation Costs by Component and Year (Nominal $000s)							
Component	2016	2017	2018	2019	2020	2021	Total
AMI	30	2,786	17,722	6,628	798	744	28,707
CFS	-	-	-	-	-	-	-
CVR	-	220	1,783	1,435	737	928	5,104
DLC	-	-	-	-	-	-	-
EDW	-	-	-	-	-	-	-
ESB	-	-	-	-	-	-	-
MDMS	-	-	-	-	-	-	-
OMS	3	1,008	2,761	4,338	13	-	8,124
CE	-	22	286	264	176	129	877
Total	**33**	**4,036**	**22,552**	**12,666**	**1,724**	**1,800**	**42,811**

Table 6

Attachment 3

Smart Grid Foundation Project

Exhibit I

Merged Outside Services Cost Details

MERGED OUTSIDE SERVICES COST DETAILS

As described in the accompanying Exhibit, the merged scenario includes outside service costs necessary to assist and manage certain aspects of the Smart Grid Foundation Project's ("SGF Project") implementation. The Hawaiian Electric Companies ("Companies") have procured external vendors, either through existing contracts or via issued requests for proposals ("RFPs"), for a portion of these services (see Exhibit E to the accompanying Application). Where available, RFP's or existing contracts where used as a reference point in the development of the costs. The total cost for outside services under the merged scenario is approximately $126 million, or roughly 40% of the total merged SGF Project implementation costs.

Table 1, below, provides the overall consolidated outside services costs by accounting treatment and utility which will be incurred during the merged SGF Project's implementation.

Merged SGF Project Outside Services Implementation Costs by Accounting Treatment ($000)				
Company	Capital	Deferred	Expense	Total
Hawaiian Electric	43,873	39,795	12,444	96,112
Hawaiʻi Electric Light	8,438	3,436	3,618	15,492
Maui Electric	7,305	3,436	3,544	14,285
Total	**59,616**	**46,667**	**19,596**	**125,889**

Table 1

Table 2 and Table 3 provide a breakout of the outside services costs for Hawaiian Electric by accounting treatment and component for each year of the merged SGF Project's implementation.

Hawaiian Electric Merged Outside Service Implementation Costs by Year (Nominal $000s)																		
	2016			2017			2018			2019			2020			2021		
	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp
AMI	801	-	-	19,079	6,464	1,720	9,879	373	257	2,881	172	178	-	84	69	-	-	70
CFS	-	-	-	19	469	24	-	3,176	732	-	1,986	382	-	-	-	-	-	-
CVR	-	-	-	1,066	-	18	408	1,104	11	105	-	21	98	-	-	168	-	-
DLC	-	-	-	-	-	21	-	634	7	1	-	6	4,561	-	-	4,093	-	-
EDW	-	-	-	39	440	27	4	430	13	11	438	22	-	417	0	-	417	0
ESB	12	-	-	414	476	432	-	437	428	-	445	436	-	424	416	-	424	416
MDMS	90	-	40	145	10,746	413	-	9,476	639	-	-	34	-	-	-	-	-	-
OMS	-	-	-	-	-	220	-	225	212	-	538	95	-	-	-	-	-	-
CE	-	-	-	-	-	2,154	-	-	990	-	-	861	-	-	483	-	-	600
Total	**904**	**-**	**40**	**20,761**	**18,595**	**5,028**	**10,291**	**15,854**	**3,289**	**2,998**	**3,579**	**2,033**	**4,659**	**926**	**968**	**4,261**	**841**	**1,086**

Table 2

Hawaiian Electric Merged Outside Services Implementation Costs by Accounting Treatment (Nominal $000s)				
Component	Capital	Deferred	Expense	Total
AMI	32,639	7,092	2,294	42,025
CFS	19	5,632	1,138	6,789
CVR	1,844	1,104	50	2,998
DLC	8,656	634	34	9,324
EDW	54	2,142	62	2,258
ESB	426	2,205	2,126	4,757
MDMS	235	20,222	1,126	21,583
OMS	-	764	526	1,290
CE	-	-	5,088	5,088
Total	**43,873**	**39,795**	**12,444**	**96,112**

Table 3

Table 4 and Table 5 provide this same break out for Hawaiʻi Electric Light, while Table 6 and Table 7 provide this break out for Maui Electric during the merged SGF Project's implementation.

Hawai‘i Electric Light Merged Outside Service Implementation Costs by Year (Nominal $000s)																		
	2016			2017			2018			2019			2020			2021		
	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp
AMI	-	-	-	1,347	-	334	2,290	-	98	3,748	-	136	0	-	15	-	-	15
CFS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CVR	-	-	-	170	-	4	268	-	2	268	-	4	163	-	-	180	-	-
DLC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EDW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ESB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MDMS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OMS	-	-	-	-	-	989	2	1,014	952	-	2,422	427	-	-	-	-	-	-
CE	-	-	-	-	-	14	-	-	212	-	-	184	-	-	103	-	-	129
Total	**-**	**-**	**-**	**1,518**	**-**	**1,342**	**2,560**	**1,014**	**1,264**	**4,017**	**2,422**	**751**	**163**	**-**	**118**	**180**	**-**	**143**

Table 4

Hawai‘i Electric Light Merged Outside Services Implementation Costs by Accounting Treatment (Nominal $000s)				
Component	Capital	Deferred	Expense	Total
AMI	7,386	-	597	7,983
CFS	-	-	-	-
CVR	1,050	-	9	1,059
DLC	-	-	-	-
EDW	-	-	-	-
ESB	-	-	-	-
MDMS	-	-	-	-
OMS	2	3,436	2,368	5,806
CE	-	-	643	643
Total	**8,438**	**3,436**	**3,617**	**15,491**

Table 5

Maui Electric Merged Outside Service Implementation Costs by Year ($000s)																		
	2016			2017			2018			2019			2020			2021		
	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp	Cap	Def	Exp
AMI	-	-	-	1,385		345	3,323	-	66	1,627	-	83	-	-	15	-	-	15
CFS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CVR	-	-	-	170	-	4	227	-	2	226	-	4	166	-	-	178	-	-
DLC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EDW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ESB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MDMS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OMS	-	-	-	-	-	989	2	1,014	952	-	2,422	427	-	-	-	-	-	-
CE	-	-	-	-	-	14	-	-	212	-	-	184	-	-	103	-	-	129
Total	**-**	**-**	**-**	**1,556**	**-**	**1,352**	**3,552**	**1,014**	**1,232**	**1,853**	**2,422**	**698**	**166**	**-**	**118**	**178**	**-**	**143**

Table 6

Maui Electric Merged Outside Services Implementation Costs by Accounting Treatment ($000s)				
Component	Capital	Deferred	Expense	Total
AMI	6,335	-	523	6,858
CFS	-	-	-	-
CVR	967	-	11	978
DLC	-	-	-	-
EDW	-	-	-	-
ESB	-	-	-	-
MDMS	-	-	-	-
OMS	2	3,436	2,368	5,806
CE	-	-	643	643
Total	**7,305**	**3,436**	**3,544**	**14,285**

Table 7

Attachment 4

Smart Grid Foundation Project

Exhibit I

Merged Project Management Office Cost Details

MERGED PROJECT MANAGEMENT OFFICE COST DETAILS

The merged Project Management Office ("PMO") costs described in the accompanying Exhibit are included in the various components (see Section IV of the accompanying Exhibit). Below is the breakdown of the allocated dollars by component. Table 1 provides these costs by Company and component, while Table 2 provides these costs broken out by Company and accounting treatment.

Total Merged SGF Project PMO Costs by Company and Component (Nominal $000s)				
Component	Hawaiian Electric	Hawai'i Electric Light	Maui Electric	Total
AMI	5,860	1,155	1,155	8,170
CFS	486	-	-	486
CVR	653	130	130	913
DLC	55	-	-	55
EDW	293	-	-	293
ESB	292	-	-	292
MDMS	1,794	-	-	1,794
OMS	93	412	412	917
CE	225	48	48	321
Total	**9,751**	**1,745**	**1,745**	**13,241**

Table 1

Total Merged SGF Project PMO Costs by Company and Component (Nominal $000s)				
Company	Capital	Deferred	Expense	Total
Hawaiian Electric	6,017	2,376	1,358	9,751
Hawai'i Electric Light	1,191	261	293	1,745
Maui Electric	1,191	261	293	1,745
Total	**8,399**	**2,898**	**1,944**	**13,241**

Table 2

The following tables present the costs specific to each component by year and type.

AMI Component PMO Costs by Year (Nominal $000s)							
	2016	2017	2018	2019	2020	2021	Total
Internal Labor	**27**	**849**	**823**	**599**	-	-	**2,298**
Capital	27	712	780	537	-	-	2,056
Deferred	-	81	5	4	-	-	90
Expense	-	56	38	58	-	-	152
Outside Service	**43**	**2,542**	**1,300**	**937**	-	-	**4,822**
Capital	43	2,134	1,232	841	-	-	4,250
Deferred	-	240	8	6	-	-	254
Expense	-	168	60	90	-	-	318
Intercompany	**21**	**369**	**347**	**313**	-	-	**1,050**
Capital	21	310	329	281	-	-	941
Deferred	-	35	2	2	-	-	39
Expense	-	24	16	30	-	-	70
Total	**91**	**3,760**	**2,470**	**1,849**	-	-	**8,170**

Table 3

CFS Component PMO Costs by Year (Nominal $000s)							
	2016	2017	2018	2019	2020	2021	Total
Internal Labor	-	**22**	**63**	**65**	-	-	**150**
Capital	-	6	-	-	-	-	6
Deferred	-	10	48	49	-	-	107
Expense	-	6	15	16	-	-	37
Outside Service	-	**66**	**99**	**101**	-	-	**266**
Capital	-	19	-	-	-	-	19
Deferred	-	29	75	76	-	-	180
Expense	-	18	24	25	-	-	67
Intercompany	-	**10**	**27**	**33**	-	-	**70**
Capital	-	3	-	-	-	-	3
Deferred	-	4	20	25	-	-	49
Expense	-	3	7	8	-	-	18
Total	-	**98**	**189**	**199**	-	-	**486**

Table 4

CVR Component PMO Costs by Year (Nominal $000s)							
	2016	2017	2018	2019	2020	2021	Total
Internal Labor	-	**71**	**109**	**88**	-	-	**268**
Capital	-	65	84	69	-	-	218
Deferred	-	-	15	-	-	-	15
Expense	-	6	10	19	-	-	35
Outside Service	-	**213**	**173**	**137**	-	-	**523**
Capital	-	196	134	107	-	-	437
Deferred	-	-	23	-	-	-	23
Expense	-	17	16	30	-	-	63
Intercompany	-	**30**	**46**	**46**	-	-	**122**
Capital	-	28	36	36	-	-	100
Deferred	-	-	6	-	-	-	6
Expense	-	2	4	10	-	-	16
Total	-	**314**	**328**	**271**	-	-	**913**

Table 5

DLC Component PMO Costs by Year (Nominal $000s)							
	2016	2017	2018	2019	2020	2021	Total
Internal Labor	-	**2**	**10**	**5**	-	-	**17**
Capital	-	-	-	1	-	-	1
Deferred	-	-	8	-	-	-	9
Expense	-	2	2	4	-	-	8
Outside Service	-	**7**	**16**	**8**	-	-	**31**
Capital	-	-	-	2	-	-	2
Deferred	-	-	13	-	-	-	13
Expense	-	7	3	6	-	-	16
Intercompany	-	**1**	**4**	**2**	-	-	**7**
Capital	-	-	-	-	-	-	-
Deferred	-	-	3	-	-	-	3
Expense	-	1	1	2	-	-	4
Total	-	**10**	**30**	**15**	-	-	**55**

Table 6

EDW Component PMO Costs by Year (Nominal $000s)							
	2016	2017	2018	2019	2020	2021	Total
Internal Labor	-	**30**	**19**	**34**	-	-	**83**
Capital	-	13	3	7	-	-	23
Deferred	-	8	8	13	-	-	29
Expense	-	9	8	14	-	-	31
Outside Service	-	**88**	**30**	**53**	-	-	**171**
Capital	-	39	5	11	-	-	55
Deferred	-	22	12	20	-	-	54
Expense	-	27	13	22	-	-	62
Intercompany	-	**13**	**8**	**18**	-	-	**39**
Capital	-	6	1	4	-	-	11
Deferred	-	3	3	7	-	-	13
Expense	-	4	4	7	-	-	15
Total	-	**131**	**56**	**105**	-	-	**293**

Table 7

ESB Component PMO Costs by Year (Nominal $000s)							
	2016	2017	2018	2019	2020	2021	Total
Internal Labor	**8**	**31**	**15**	**27**	-	-	**81**
Capital	8	8	-	-	-	-	16
Deferred	-	18	8	14	-	-	40
Expense	-	5	7	13	-	-	25
Outside Service	**12**	**93**	**25**	**41**	-	-	**171**
Capital	12	25	-	-	-	-	37
Deferred	-	52	13	21	-	-	86
Expense	-	16	12	20	-	-	48
Intercompany	**6**	**14**	**6**	**14**	-	-	**40**
Capital	6	4	-	-	-	-	10
Deferred	-	8	3	7	-	-	18
Expense	-	2	3	7	-	-	12
Total	**26**	**137**	**46**	**82**	-	-	**292**

Table 8

MDMS Component PMO Costs by Year (Nominal $000s)							
	2016	2017	2018	2019	2020	2021	Total
Internal Labor	**82**	**210**	**175**	**22**	-	-	**489**
Capital	57	3	-	-	-	-	60
Deferred	-	189	153	-	-	-	342
Expense	25	18	22	22	-	-	87
Outside Service	**131**	**627**	**273**	**34**	-	-	**1,065**
Capital	91	9	-	-	-	-	100
Deferred	-	564	238	-	-	-	802
Expense	40	54	35	34	-	-	163
Intercompany	**65**	**91**	**73**	**11**	-	-	**240**
Capital	45	1	-	-	-	-	46
Deferred	-	82	64	-	-	-	146
Expense	20	8	9	11	-	-	48
Total	**278**	**928**	**521**	**67**	-	-	**1,794**

Table 9

OMS Component PMO Costs by Year (Nominal $000s)							
	2016	2017	2018	2019	2020	2021	Total
Internal Labor	-	**27**	**75**	**187**	-	-	**289**
Capital	-	-	3	-	-	-	3
Deferred	-	-	44	147	-	-	191
Expense	-	27	28	40	-	-	95
Outside Service	-	**81**	**118**	**289**	-	-	**488**
Capital	-	-	4	-	-	-	4
Deferred	-	-	69	226	-	-	295
Expense	-	81	45	63	-	-	189
Intercompany	-	**12**	**31**	**97**	-	-	**140**
Capital	-	-	1	-	-	-	1
Deferred	-	-	18	76	-	-	94
Expense	-	12	12	21	-	-	45
Total	-	**120**	**224**	**573**	-	-	**917**

Table 10

Customer Engagement Component PMO Costs by Year (Nominal $000s)							
	2016	2017	2018	2019	2020	2021	Total
Internal Labor	-	**32**	**24**	**35**	-	-	**91**
Capital	-	-	-	-	-	-	-
Deferred	-	-	-	-	-	-	-
Expense	-	32	24	35	-	-	91
Outside Service	-	**96**	**37**	**55**	-	-	**188**
Capital	-	-	-	-	-	-	-
Deferred	-	-	-	-	-	-	-
Expense	-	96	37	55	-	-	188
Intercompany	-	**14**	**10**	**18**	-	-	**42**
Capital	-	-	-	-	-	-	-
Deferred	-	-	-	-	-	-	-
Expense	-	14	10	18	-	-	42
Total	-	**142**	**71**	**108**	-	-	**321**

Table 11

Attachment 5

Smart Grid Foundation Project

Exhibit I

Merged Economic Analysis Details

MERGED ECONOMIC ANALYSIS DETAILS

Similar to the unmerged scenario (see Attachment 11 of Exhibit B to the accompanying Application), the Hawaiian Electric Companies ("Companies") performed an economic analysis to understand the impact of the Smart Grid Foundation Project ("SGF Project") under the merged scenario through 2036 (time frame representative of the longest useful life of the smart meters). Under the merged business case, the SGF Project is expected to nominally cost in revenue requirements $11 million, $18 million, and $6 million at Hawaiian Electric, Maui Electric, and Hawai‘i Electric Light respectively. See detailed information in Table 1, below.

Year	Hawaiian Electric	Maui Electric	Hawai‘i Electric Light	Consolidated
2016	1,266	4	4	1,274
2017	16,280	1,479	1,459	19,218
2018	20,099	2,667	2,508	25,274
2019	19,902	3,274	3,424	26,600
2020	16,190	3,859	4,990	25,039
2021	16,052	3,314	3,990	23,356
2022	17,181	3,813	4,200	25,194
2023	11,119	3,005	3,341	17,465
2024	9,129	2,660	2,885	14,674
2025	6,470	2,195	1,999	10,663
2026	3,310	1,824	1,573	6,707
2027	2,933	1,573	1,252	5,758
2028	(1,904)	1,316	1,010	422
2029	(5,756)	644	(343)	(5,455)
2030	(11,287)	(695)	(1,995)	(13,977)
2031	(13,422)	(1,502)	(2,861)	(17,784)
2032	(14,870)	(1,873)	(3,280)	(20,023)
2033	(17,426)	(2,232)	(3,749)	(23,407)
2034	(20,673)	(2,665)	(4,325)	(27,663)
2035	(20,860)	(2,208)	(4,697)	(27,765)
2036	(22,642)	(2,521)	(4,947)	(30,110)
TOTAL	**$11,093**	**$17,929**	**$6,436**	**$35,458**
Present Value Revenue Requirements	**$60,821**	**$15,458**	**$13,437**	**$89,716**

Values presented are in nominal ($000s), and numbers may not tie due to rounding.

Table 1

In order to model the Merged SGF Project costs in a manner that most inclusively reflects the cost of the implementation, the economic analysis used the following assumptions:

- Useful life by various asset are provided in Attachment 6 of Exhibit Be to the accompanying Application;
- Cost estimates are based on preliminary design and include high level cost assumptions. Estimates may change once final design and engineering is completed and contracts from external parties are confirmed;
- Recovery of costs is assumed as the proposed preferred option as provided in Exhibit G to the accompanying Application;
- Economic analysis and calculation includes the total (not average) deferred Merged SGF Project cost;
- Sales forecast based on the February 2016 Power Supply Improvement Plan filing using the low fuel forecast, no conversion to LNG, and no modernization of existing units;
- Typical residential customer consumes an average of 500 kWh/month;
- Financial inputs assumed as follows:
  - Discount rate = 8.076%;
  - Federal income tax rate = 32.9% effective;
  - State income tax rate = 6.0% effective;
  - State investment tax credit = 4.0%;
  - Composite revenue tax rate = 8.9%; and
  - Bonus depreciation at 50% through 2017, 40% in 2018, and 30% in 2019

I. SIMULATED TYPICAL RESIDENTIAL BILL ANALYSIS

Under the merged scenario, through the 21-year analysis timeframe for the SGF Project, the typical residential customer using 500 kWh per month will pay on average $0.03 at Hawaiian Electric, $0.38 at Maui Electric, and $0.14 at Hawai‘i Electric Light. See detailed information for the various scenarios in Figure 1, below.

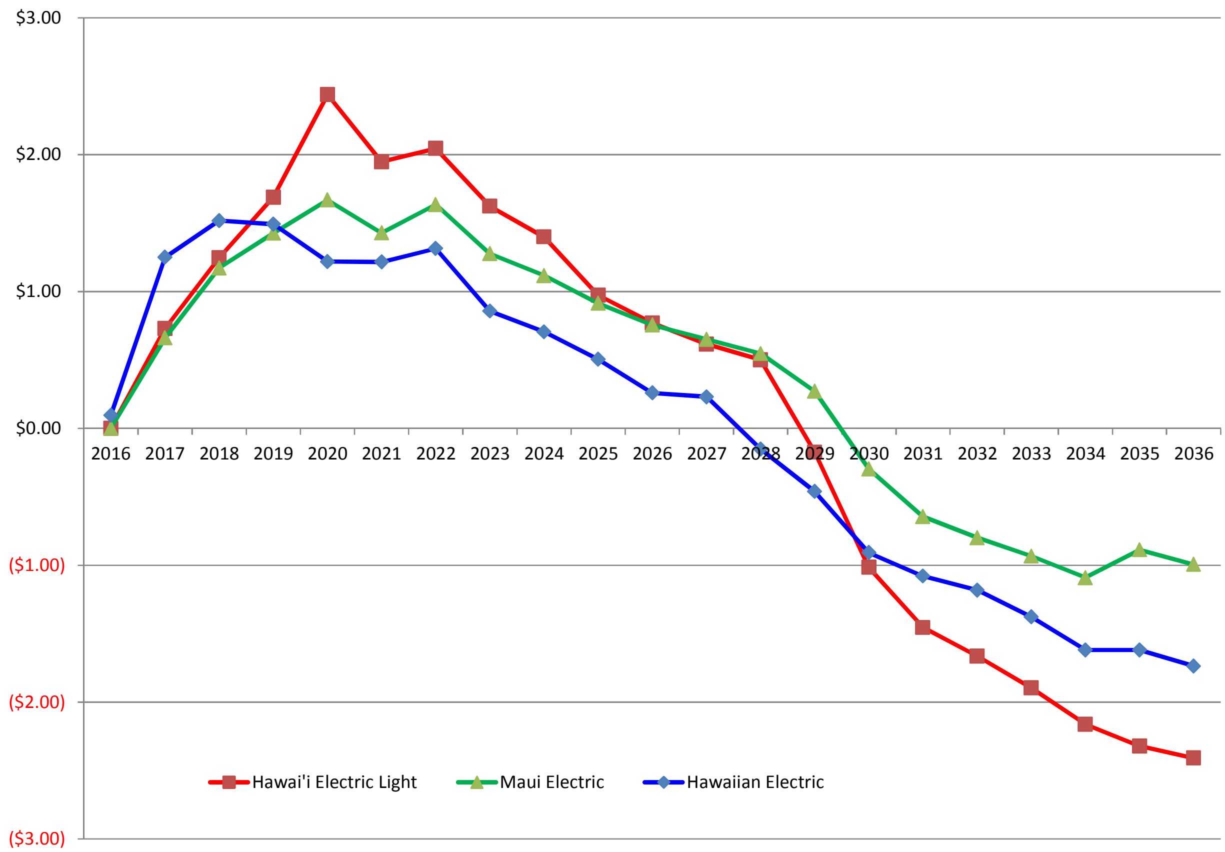

Figure 1

The following data are the individual company simulated typical residential bill analyses:

A. HAWAIIAN ELECTRIC

Inclusion of Hawaiian Electric's share of the SGF Project cost in rate base in 2016 will result in residential customers on O'ahu experiencing a financial impact that will peak in 2018 at $1.52. Benefits are realized during the second year with overall bill savings starting in 2028. Table 2 provides the estimated customer impact by year.

Year	Total Cost	Sales Forecast	Cost per kWh	Average Monthly Financial Impact
2016	1,265,862	6,531,436	0.0194	0.10
2017	16,279,936	6,505,354	0.2503	1.25
2018	20,099,370	6,619,726	0.3036	1.52
2019	19,902,272	6,667,307	0.2985	1.49
2020	16,190,456	6,639,645	0.2438	1.22
2021	16,052,230	6,599,452	0.2432	1.22
2022	17,180,766	6,532,535	0.2630	1.32
2023	11,118,786	6,484,788	0.1715	0.86
2024	9,128,714	6,465,208	0.1412	0.71
2025	6,469,737	6,408,757	0.1010	0.50
2026	3,310,171	6,376,824	0.0519	0.26
2027	2,933,288	6,344,210	0.0462	0.23
2028	(1,903,619)	6,329,250	(0.0301)	(0.15)
2029	(5,755,849)	6,256,520	(0.0920)	(0.46)
2030	(11,287,123)	6,216,751	(0.1816)	(0.91)
2031	(13,421,799)	6,220,292	(0.2158)	(1.08)
2032	(14,869,941)	6,296,324	(0.2362)	(1.18)
2033	(17,425,657)	6,330,129	(0.2753)	(1.38)
2034	(20,672,813)	6,386,995	(0.3237)	(1.62)
2035	(20,859,565)	6,443,810	(0.3237)	(1.62)
2036	(22,641,806)	6,523,777	(0.3471)	(1.74)
			Average	**$0.03**

Table 2

- The 2018 financial impact peak is primarily due to capital costs of $66 million for 2017 starting to depreciate. $29 million of these capital costs are for new meters in the AMI subproject.
- The 2020 financial impact decrease is primarily due to an increase in expense benefits of $6 million or 45% from the prior year. These benefits are primarily related to the CVR subproject.
- The 2022 financial impact increase is primarily due to an increase in expenses of $2.3 million or 19% from the prior year. These costs are for software-as-a-service ("SaaS")/manage services, post-project labor offset by decreases in EDW and Customer Engagement.
- The 2023 financial impact decrease is primarily driven by a decrease in expense of $3.9 million or 26% from the prior year. This decrease is due to savings in the Saas/licensing expenses and security.
- The 2026-27 financial impact stays relatively flat due to expenses being $2 million or 16% higher in 2027 as compared to 2026. These expenses are primarily attributable security and CFS hardware replace/upgrade which offsets the increase in benefits.

- The 2034-35 financial impact stays relatively flat due to expenses increasing by $162,000, or 1% from the prior year. These costs are primarily related to hardware replacement costs being incurred.

B. MAUI ELECTRIC

Inclusion of Maui Electric's share of the SGF Project cost in rate base in 2016 will result in residential customers on Maui, Lanaʻi, and Molokaʻi experiencing a bill impact that will peak in 2020 at $1.67. Benefits are realized during the second year with overall bill savings starting in 2030. Table 3 provides the estimated customer impact by year.

Year	Total Cost	Sales Forecast	Cost per kWh	Average Monthly Financial Impact
2016	3,819	1,117,533	0.0003	0.00
2017	1,478,908	1,116,995	0.1324	0.66
2018	2,667,183	1,137,384	0.2345	1.17
2019	3,273,997	1,147,496	0.2853	1.43
2020	3,858,506	1,156,187	0.3337	1.67
2021	3,313,600	1,159,632	0.2857	1.43
2022	3,812,759	1,165,940	0.3270	1.64
2023	3,005,346	1,177,047	0.2553	1.28
2024	2,659,833	1,190,201	0.2235	1.12
2025	2,194,677	1,198,739	0.1831	0.92
2026	1,823,699	1,207,639	0.1510	0.76
2027	1,573,079	1,208,298	0.1302	0.65
2028	1,315,582	1,202,551	0.1094	0.55
2029	644,090	1,184,130	0.0544	0.27
2030	(694,992)	1,171,454	(0.0593)	(0.30)
2031	(1,501,645)	1,165,422	(0.1288)	(0.64)
2032	(1,872,971)	1,174,189	(0.1595)	(0.80)
2033	(2,232,003)	1,196,255	(0.1866)	(0.93)
2034	(2,664,795)	1,222,360	(0.2180)	(1.09)
2035	(2,208,484)	1,245,454	(0.1773)	(0.89)
2036	(2,521,103)	1,268,654	(0.1987)	(0.99)
			Average	**$ 0.38**

Table 3

- The 2020 financial impact peak is primarily due to an increase in expenses of $3.4 million, or 32 % from the prior year, related to the retirement of old meters, offset by a decrease in post-project labor and OMS.
- The 2021 financial impact decrease is primarily due to expenses decreasing by $134,000, or 4% from the prior year, related to a decrease in expenses related to meter support and OMS post in-service labor allocation.

- The 2022 financial impact increase is primarily due to expenses increasing by $597,000, or 18% from the prior year. These increases are attributable to SaaS to Licensed Managed conversion and post-project labor starting for components with five-year durations.
- The 2030 financial impact decrease is primarily due to expenses decreasing by $800,000, or 24% from the prior year due to a decrease in expenses related to the retirement of old meters.
- The 2035 financial impact increase is due to benefits decreasing slightly from the prior year by $500,000, or -7%.

C. HAWAI‘I ELECTRIC LIGHT

Inclusion of Hawai‘i Electric Light’s share of the SGF Project cost in rate base in 2016 will result in residential customers on Hawai‘i Island experiencing a financial impact that will peak in 2020 at $2.44. Benefits are realized during the second year with overall bill savings starting in 2029. Table 4 provides the estimated customer impact per year.

Year	Total Cost	Sales Forecast	Cost per kWh	Average Monthly Financial Impact
2016	3,819	1,014,734	0.0004	0.00
2017	1,458,852	999,637	0.1459	0.73
2018	2,507,667	1,005,643	0.2494	1.25
2019	3,423,947	1,013,881	0.3377	1.69
2020	4,989,710	1,022,952	0.4878	2.44
2021	3,989,771	1,024,249	0.3895	1.95
2022	4,200,091	1,026,712	0.4091	2.05
2023	3,341,298	1,028,915	0.3247	1.62
2024	2,885,359	1,031,100	0.2798	1.40
2025	1,998,590	1,026,451	0.1947	0.97
2026	1,572,812	1,022,633	0.1538	0.77
2027	1,251,834	1,014,957	0.1233	0.62
2028	1,010,140	1,007,190	0.1003	0.50
2029	(343,270)	989,564	(0.0347)	(0.17)
2030	(1,994,673)	983,232	(0.2029)	(1.01)
2031	(2,861,027)	983,960	(0.2908)	(1.45)
2032	(3,280,212)	986,123	(0.3326)	(1.66)
2033	(3,749,105)	989,122	(0.3790)	(1.90)
2034	(4,324,968)	1,000,462	(0.4323)	(2.16)
2035	(4,697,225)	1,012,234	(0.4640)	(2.32)
2036	(4,947,484)	1,027,392	(0.4816)	(2.41)
			Average	**$0.14**

Table 4

- The 2020 financial impact peak is primarily due expenses increasing by $1 million, or 37% from the prior year, driven by expenses related to the retirement of old meters.
- The 2021 financial impact decrease is primarily due to a decrease of expenses of $100,000, or 3% from the prior year, related to OMS and Customer Engagement.
- The 2022 financial impact increase is primarily due to an increase in expenses of $4 million, or 13% from the prior year, related to maintenance and post-project labor.
- The 2029 – 2030 sharp financial impact decrease is primarily due a decrease in expenses in 2029 and 2030 of $500,000 and $1 million, respectively, from the prior years. These decreases are from expenses related to the retirement of old meters.

<u>VERIFICATION</u>

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

JOSEPH P. VIOLA, being first duly sworn, deposes and says: That he is a Vice President, Regulatory Affairs of Hawaiian Electric Company, Inc., 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 HAWAIIAN ELECTRIC COMPANY, INC., HAWAI'I ELECTRIC LIGHT COMPANY, INC. and MAUI ELECTRIC COMPANY, LIMITED, and is authorized so to do; that he has read the foregoing Application, and knows the contents thereof; and that the same are true to the best of his knowledge except as to matters stated on information or belief or that are specific to NextEra Energy, Inc. (and/or its affiliates), and that as to those matters he believes them to be true.

Joseph P. Viola

DEBORAH ICHISHITA NOTARY 04-409 PUBLIC STATE OF HAWAII

Subscribed and sworn to before me this 31st day of March 2016.

Deborah Ichishita

Notary Public, First Circuit,
State of Hawai'i

My Commission expires July 18, 2016

STATE OF HAWAI'I NOTARY CERTIFICATION

Doc. Date: 3/31/2016 # of pages 1,991

Notary Name: DEBORAH ICHISHITA First Circuit

Doc. Description: Application, Exhibits A - I, Verification

Deborah Ichishita 3/31/16

Signature Date

DEBORAH ICHISHITA NOTARY 04-409 PUBLIC STATE OF HAWAII

VERIFICATION

STATE OF FLORIDA)
)
PALM BEACH COUNTY)

BRIAN HANRAHAN, being first duly sworn, deposes and says: That he is the Director of In-Home Technologies and Electric Vehicles at Florida Power & Light Co. ("FPL") and the leader of the FPL Smart Grid team that assisted the Hawaiian Electric Companies, that he makes this verification for and on behalf of NextEra Energy, Inc. and is authorized so to do; that he has read the foregoing Application, and that he attests to the contents of Exhibit I to the Application, specifically including the following: (1) the assumptions in the merged scenario, but only to the extent that they differ from those in the unmerged scenario; (2) the cost estimates in the merged scenario, but only insofar as they that differ from those in the unmerged scenario (excluding loaders and AFUDC); and (3) the project schedule for the merged scenario; 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.

Brian Hanrahan

Subscribed and sworn to beforeme this 30th Day of March, 2016

Michelle Lall

Notary Public, State of Florida

My Commission expires June 15, 2018

NOTARY PUBLIC STATE OF FLORIDA
MICHELLE LALL
MY COMMISSION #FF132561
EXPIRES June 15, 2018
(407) 398-0153 FloridaNotaryService.com

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. and MAUI ELECTRIC COMPANY, LIMITED For approval to commit funds in excess of $2,500,000 for the Smart Grid Foundation Project, to Defer Certain Computer Software Development Costs, to Recover the Capital and Deferred Costs through the Renewable Energy Infrastructure Surcharge, and Related Requests.	)	Docket No.

CERTIFICATE OF SERVICE

I hereby certify that I have this date served two copies of the foregoing APPLICATION OF HAWAIIAN ELECTRIC COMPANY, INC., HAWAIʻI ELECTRIC LIGHT COMPANY, INC. AND MAUI ELECTRIC COMPANY, LIMITED, VERIFICATION, and EXHIBITS A-I, together with this CERTIFICATE OF SERVICE, by making personal service to the following and at the following address:

Jeffrey T. Ono
Executive Director
Division of Consumer Advocacy
Department of Commerce and Consumer Affairs
335 Merchant Street, Room 326
Honolulu, Hawaiʻi 96813

DATED: Honolulu, Hawaiʻi, March 31, 2016.

HAWAIIAN ELECTRIC COMPANY, INC.

Robert Pytlarz