June 18, 2021

The Honorable Chair and Members
of the Hawai‘i Public Utilities Commission
Kekuanao‘a Building, 1st Floor
465 South King Street
Honolulu, Hawai‘i 96813

Dear Commissioners:

Subject: Docket No. 2019-0323
Instituting a Proceeding to Investigate Distributed Energy Resource Policies
Hawaiian Electric's EDRP / SDP Implementation Plan

In accordance with Order No. 37816, issued on June 8, 2021 in the subject proceeding, Hawaiian Electric[1] respectfully submits its proposed Emergency Demand Response Program ("EDRP")/ Scheduled Dispatch Program ("SDP") Implementation Plan for the Commission's review and approval. The Company is also submitting projected timeline and funds expenditure information to increase Fast Demand Response Program enrollment to its authorized 7 MW capacity, as required by Order No. 37816.

Sincerely,

/s/ Kaiulani Shinsato

Kaiulani Shinsato
Director
Customer Energy Resources Programs

Enclosures

[1] Hawaiian Electric Company, Inc., Hawai‘i Electric Light Company, Inc., and Maui Electric Company, Limited (collectively referred to herein as "Hawaiian Electric" or the "Company") are each doing business as "Hawaiian Electric" and have jointly registered "Hawaiian Electric" as a trade name with State of Hawaii Department of Commerce and Consumer Affairs, as evidenced by Certificate of Registration No. 4235929, dated December 20, 2019.

Proposed Emergency Demand Response/ Scheduled Dispatch Program Implementation Plan

Introduction

On June 8, 2021, the Commission issued Decision and Order No. 37816 ("D&O 37816") in Docket No. 2019-0323 approving the Emergency Demand Response Program ("EDRP") and its associated Scheduled Dispatch Program ("SDP") Rider to mitigate the possible resource shortfall following the September 2022 retirement of the AES coal plant on Oahu.

The Commission ordered the Company to:

1) commence replacement activities as soon as possible to enhance the Fast DR program to its full 7 MW capacity;

2) establish the SDP by July 1, 2021, in accordance with the requirements provided in D&O 37816; and

3) file with the Commission its SDP Implementation Plan on or before June 18, 2021.[1]

The table below summarizes key program requirements set forth by the Commission in D&O 37816.

Table 1: SDP Key Program Requirements

Description	Requirement
Island	Oahu
Program Cap	50 MW
Incentive (one-time)	$850/kW (first 15 MW) $750/kW (next 15 MW) $500/kW (final 20 MW)
Contract Length	10 years
Battery delivery	"hard-scheduled" one 2-hour event duration during peak hours
Additional Generation	Up to 5 kW allowed without invalidating customers' underlying DER interconnection agreement
Performance	Up to $100/month penalty if battery not performing to committed capacity
Termination	Prorated portion of the upfront incentive payment must be returned at contract termination

The Program start date of July 1, 2021, is defined as the beginning of the Initial Phase where a key requirement for the participating battery will be the "hard-scheduled" two-hour event duration during peak hours. The Initial Phase will end on December 31, 2023, at which point the Final Phase will

[1] *See* D&O 37816 at 34.

commence. During the Final Phase, program participants may either continue in the SDP or transition into a different program offering or rider under EDRP with new program requirements (e.g., a remote dispatch program also referred to as controllable program)[2] that will be set forth by the Commission in a forthcoming order. The enrollment period has an earlier end date of June 20, 2023, or when the program enrolls 50 MW, whichever comes first.

This Implementation Plan covers the information directed by the Commission in D&O 37816, specifically: the steps necessary to implement the SDP, a feasible schedule for program implementation, and relevant supporting information including drafts of required tariff amendments, contract amendments, and participation agreements.

Fast DR Replenishment Plan

As part of the EDRP development, the Commission ordered the replenishment of Oahu's Fast DR Program back to its capacity of 7 MW. The Company intends to reach the 7 MW capacity by adding 2.657 MW[3] of capacity by the end of 2022. The Company is targeting 1.010 MW of additional Fast DR capacity by the end of 2021, and the remaining 1.647 MW in 2022. Using an average incentive cost of $250/kW, the Company projects spending $252,500 in 2021 and $664,250 in 2022. Annually, the Company has been underspending the authorized incentive budget by more than $750,000, such that the forecasted spend to replenish the Fast DR Program spanning two years is well within the available incentive budget. The Demand Response Adjustment Clause ("DRAC") will continue to reconcile on a quarterly basis the DR expenses embedded in the Company's base rates with the actual DR expenses incurred, and return to customers the unspent amount.

The Company is currently working with existing customers to potentially add additional capacity. The Company is also working on identifying and reaching out to prospective customers that are ideal for the Fast DR Program. With contract negotiation and equipment upgrades, an implementation timeline has taken on average six months. The Company anticipates the added capacity in 2021 will occur in the fourth quarter, while the remaining capacity in 2022 will occur throughout the year. The table below summarizes the plan to replenish the 2.6557 MW.

Table 2: Fast DR Replenishment Forecast and Budgeting

CUSTOMER SEGMENT	NO. OF ACCTS	FAST DR LOAD (kW)	INCENTIVE
2020 Fast DR Capacity	20	4,722	
2021 Q2 Terminated Capacity	(2)	(379)	
2021 Q2 Fast DR Capacity	18	4,343	
Military	1	700	$175,000
Condos	1	150	$37,500
Hotels	2	160	$40,000
2021 Added Capacity	**4**	**1,010**	**$252,500**
2022 Added Capacity	**10**	**1,647**	**$411,750**

[2] *See* discussion of "alternative dispatch program" at page 31 of D&O 37816.
[3] As of Q2 2021, the capacity of the Fast Demand Response Program is 4.343 MW. A contract for a military account and customer from the education sector are undergoing the termination process. These customers have been suspended from the program for several years due to under performance and have shown no interest in rectifying their performance issues.

CUSTOMER SEGMENT	NO. OF ACCTS	FAST DR LOAD (kW)	INCENTIVE
2022 Q4 Fast DR Capacity	**32**	**7,000**	**$664,250**

The Company will coordinate with its current contractor as well as its Key Account Management team to identify prospective customers. If the Company is able to identify a queue of customers, the Company will re-submit its request to expand the Fast DR Program by an appropriate amount in 2022.

Implementation Plan and Schedule

The Company's Implementation Plan consists of eight (8) milestone dates. Initial milestones are intended to set up enrollment for the SDP as quickly as possible, while at the same time providing adequate time for education and training to customers, installers, and internal Company resources. The Company believes it is critical to conduct robust outreach, education, and training to solar contractors, customers, and stakeholders to ensure a smooth and successful launch of this new program.

The SDP represents a brand-new program, involving new requirements, incentives, payment arrangements, enrollment process (both mid-term through the Customer Interconnection Tool ("CIT") and interim through a paper Amendment Form), and verification process. The Company will need time to educate contractors on the new requirements and processes, solicit their feedback, and work out any issues or unintended barriers in the process before full launch of accepting applications to the SDP.

The Company's and DER Parties' prior experience in launching new programs highlights the importance of proper education and training prior to starting new programs. For the launch of the Customer Grid Supply ("CGS") and Customer Self Supply ("CSS") Programs, the Company rushed to do this within a Commission-approved short window. However, the Company received feedback from solar contractors that there was confusion over the new programs and insufficient training and resources, such that enrollment in the CGS and CSS programs got off to a slow start. To avoid this type of situation from reoccurring, the Company believes one month is a reasonable and sufficient time to conduct robust outreach and training with contractors and stakeholders, and as a result has designated August 1, 2021, as the Interim Go-Live date when enrollments will be accepted. The EDRP tariff will be effective as of July 1, 2021, and therefore any new DER applications submitted during this time will be honored and accepted to participate in the SDP program.

That said, if the Commission prefers an earlier enrollment start date for SDP, the Company believes that it may be possible to begin accepting requests as early as July 19, 2021. However, in this scenario, the Company is concerned that it will not have sufficient time to properly notify and educate all interested installers and customers on the SDP.

Implementation Plan milestone dates are presented in the table below.

Table 3: Company's Implementation Plan Milestones

Milestone	Completed Date
Stakeholder Meeting - SDP Process Overview	8/1/2021
Interim Go-Live (Manual)[(a)]	8/1/2021
Program Administration Updates	8/1/2021

Milestone	Completed Date
SAP Updates	9/15/2021
Marketing & Education	9/30/2021
Demand Response Management System ("DRMS") Updates	9/30/2021
SDP CIT Go-live	11/1/2021
Performance Requirement Process	2/28/2022

Note (a): The EDRP tariff will be effective as of July 1, 2021, and any new DER applications submitted during this time will be honored and accepted to participate in the SDP program.

Implementation Plan milestone dates represent the completion of the major implementation components required to launch and manage the EDR program. Each milestone consists of a series of high-level tasks that support achievement of the milestone:

Stakeholder Meeting - SDP Process Overview. As discussed above, the Company intends to perform stakeholder outreach through "open house" or "road show" style meetings. Materials will be prepared for these meetings, e.g., presentations, FAQ sheets, etc., and shared with attendees.

Interim Go-Live (Manual). Interim Go-Live (Manual) consists of tasks required to process SDP enrollment requests and approvals for the short period while automated enrollment for SDP is being built into CIT. These tasks include updating existing forms and creating new manual processes for processing, tracking, and reporting for program enrollment status.

Program Administration Updates. Program Administration Updates consists of tasks related to developing the process to ensure accurate incentive calculation and payment, including secure data exchange, calculation tools and their requisite governance.

SAP Updates. Updates to SAP will be required to prepare and issue customer incentive payments. Incentive payments will be in the form of check payments which, at the scale for SDP, are a departure from other DR programs that pay incentives in the form of bill credits. Further, this incentive is considered revenue or income to the respective customer and is taxable by the Internal Revenue Service ("IRS"). Therefore, at the end of the year, a 1099 form will be issued to customers receiving this incentive and that information will also be provided to the IRS. As a result, the Company will require Form W-9 information from customers to fully participate and receive the incentive from the Company. The secure data exchange mentioned above in the Program Administration Update is for this documentation to protect customer privacy.

Marketing & Education. Marketing & Education tasks consist of initiating an education and training program for installers and customers, including the development of training materials. Marketing of the EDR Program will consist of outreach via web update, social media, and press release as discussed below.

DRMS Updates. Although SDP is a non-controllable DER Program, the DRMS, as the system of record for DR enrollment will still play a key role recording and tracking SDP participation. CIT will perform the intake application where the battery capacity and any additional solar generation will be recorded. However, SDP committed capacity may be different from the capacity of installed resources and that is why the DRMS will be the record keeper of participant information and committed capacity so customer and kW enrolled in SDP can be tracked. The DRMS is also the mechanism for SAP integration which will be leveraged to provide incentive payments to customers. To enable this process, a new program in DRMS must be configured and new reports must be developed.

<u>SDP CIT Go-live.</u> The Company, solar contractors, and customers have a proven successful track record with CIT, and the Company seeks to provide a streamlined, efficient, and transparent experience in applying for SDP, similar to other DER programs integrated into CIT. Accordingly, the Company believes that the ideal platform for SDP application intake is CIT. The Company will work with the CIT vendor to add another workflow that matches the EDRP's SDP enrollment. The most recent update to CIT's workflow with NEM+ took roughly three months for full implementation and testing. The Company intends to keep a similar timeline as shown in the table below.

<u>Performance Requirement Process.</u> After the enrollment and initial implementation process is established, the Company will place its focus on developing and implementing a transparent process for performance auditing.

The Implementation Plan Schedule is presented in the following table.

Table 4: Company's Implementation Plan High Level Task List

Task	Jul 2021	Aug 2021	Sep 2021	Oct 2021	Nov 2021	Dec 2021	Jan 2022	Feb 2022
Stakeholder Meeting - SDP Process Overview		*						
Interim Go-Live (Manual)		*						
Update/Develop Forms, Procedures, Tracking								
Program Administration Updates		*						
Develop Verification Operation and Committed Capacity Process and Tools								
Develop/Implement SOX Controls and Reporting								
Configure Secure File Transfer								
SAP Updates			*					
Add SDP, including accounts								
Develop/Implement Incentive Payment Process (customer and installer)								
Marketing & Education			*					
Develop Marketing and Training Materials								
Provide Training for Installers								
Provide Training for Company (e.g., application processors, Customer Service Representatives)								
DRMS Updates			*					
Add SDP								

Task	Jul 2021	Aug 2021	Sep 2021	Oct 2021	Nov 2021	Dec 2021	Jan 2022	Feb 2022
Develop Enrollment Procedures								
Develop Reports (e.g., SDP tracking, incentives)								
SDP CIT Go-live					*			
Requirements for SDP workflow								
SOW for Vendor/Contract Execution								
Software Development and Deployment								
Performance Requirement Process								*
Develop/Implement Failure to Perform Data and Alerts								
Develop/Implement Performance Calculation Tool								
Develop Customer Payback Process								

Note: "*" identifies implementation milestone dates.

Operational Requirements

The EDRP is intended to mitigate the potential shortfall when the AES coal plant is retired in September 2022. However, this initial program is based on scheduled dispatch, which means there is no control and the battery storage systems will deliver what is scheduled regardless of grid conditions. In this scenario, 50 MW of distributed energy resources in its entirely automatically discharging at the same time period, starting at 6:00 p.m. and stopping at 8:00 p.m. could result in an unanticipated system disturbance. Another model for the provision of grid services, the Grid Service Purchase Agreement ("GSPA"), has a ramping requirement to avoid adverse situations that may occur when removing or adding large resources to the system contemporaneously. The Company's System Operators recommend this 50 MW resource be available during the timeframe of 6:00 p.m. to 8:00 p.m., but that the resource have a 2 MW per minute ramping requirement. This means a 50 MW resource would take 25 minutes to reach its full capacity.

The Company met with the DER Parties to discuss this requirement and explore solutions to implement this ramping capability. The Company was informed that the current national certification requirement does not account for this type of requirement. Therefore, one option is to create a self-certification approach where specific inverters that are qualified by the Company could deliver this ramping rate and participate in the SDP. However, the Company does not recommend this approach due generally to multiple challenges the Company experienced with self-certification for advanced inverters, and its resource intensive nature.

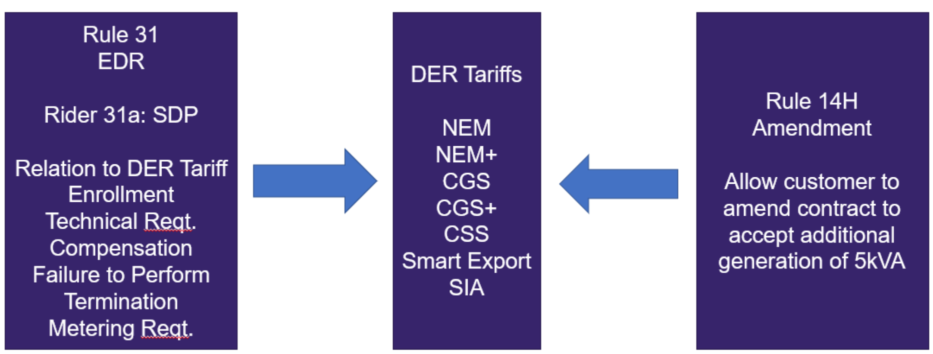
The Company's preferred solution is to set up twenty-five unique time blocks (i.e., 6:00, 6:01, 6:02, etc.) with each time block enrolling up to 2 MW of battery delivering SDP. While, the initial configuration would be a manually intensive process, it is the safest way to ensure that grid reliability is maintained during the operation of the SDP. Collaboration with the DER parties has indicated that most inverters will likely be capable of scheduling dispatch with 1-minute granularity, but some systems may not be capable. The Company will reserve certain larger time blocks at five, ten, or fifteen minutes (e.g., 6:05, 6:10, 6:15) for such inverters that the Company is notified are incapable of the one-minute time blocks.

The Company proposes 2 MW/minute as the operational requirement to participate in the SDP. However, at this time, the Company does not have a final implementable solution, and will continue to work with the DER Parties to refine a solution to deliver the 50 MW in the SDP.

Summary of Tariffs and Interrelation

To implement the EDRP, the Company proposes developing a new rule for EDRP (Rule 31) and adding a rider under Rule 31 for the SDP (Rider 31a). In doing so, any further modifications to the EDRP could be done through additional riders, such as for remote dispatch in the Commission's forthcoming order.

The objective of Rule 31 is to capture the technical and program requirements necessary to deliver emergency peak reduction, while maintaining the requirements of the underlying DER tariffs in which customers are already enrolled. Therefore, EDR is not a replacement to interconnection agreements already executed with customers. For example, a NEM customer enrolling in EDR is still a NEM customer contractually and legally. EDR enrollment will be through an amendment to the customer's existing interconnection agreement, rather than invalidating the customer's existing interconnection agreement. In addition, the Company proposes an amendment to Rule 14H to include a statement that allows customers to increase their capacity by 5 kVA if enrolled into an EDR program. This protects the customer and maintains their enrollment in their existing tariffs. If the customer chooses to enroll a capacity generation larger than 5 kVA the customer will void their existing tariff and will have to enroll into a new DER tariff that is currently accepting new applications. The figure below outlines the interrelation between the new rule for EDRP (Rule 31), existing tariffs (Rules 18, 22, 23, 24, 25 and 27), and the amendment to Rule 14H. This Implementation Plan does not propose any amendments to existing DER tariffs.



The implementation of the SDP will result in a generation increase of up to 50 MW. However, this generation is meant to deliver the necessary load reduction during the peak period.[4] To streamline SDP implementation, the Company proposes to track generation from SDP applications as SDP capacity, rather than adding capacity to existing underlying tariffs/programs. This ensures that SDP capacity does not impact the caps of already closed programs or fill the capacity in existing DER programs. For reporting, the Company will provide a separate line item from other DER programs for SDP generation.

[4] *See* D&O 37816 at 24: "[t]he Commission is prioritizing meeting the urgent peak demand capacity needs via the SDP." *See also* D&O 37816 at 27: "Dispatch is expected to be scheduled during the system peak."

While the SDP may seem to be its own DER program, customers will be compensated at the export rate of the DER program in which they are enrolled.

The interconnection tariffs have inconsistent terminology when referring to units of electric power, VA and W. While the units of power are similar, Watts do not recognize the contribution of reactive power. The Company will consider the potential ramifications of both and clarify the units to be consistent prior to the final tariff rule and amendment publication.

In D&O 37816, the Commission stated: "Customers shall be required to manage their DER systems to automatically prioritize battery charging during periods of substantial solar panel insolation in order to most reliably serve the two-hour battery discharge commitment as scheduled by Hawaiian Electric."[5] To ensure added generation is for the battery to deliver SDP, the Company added a statement in Rule 31 requiring that the storage must be at least twice the size of the newly installed PV (e.g., 10 kWh battery for a 5 kW PV system.)

SDP Approval Process – New and Existing Customers

The purpose of SDP is to provide export during a specified period of the day (one two-hour duration during the system peak). The quickest way to review and enable the systems participating in this program is to ensure the incremental export is occurring during this scheduled period only, as export of energy during other periods may pose risks to the grid, such as exceeding local (i.e., distribution circuit) hosting capacity limits. While the Company stands committed to increase the export of customer-sited systems, managing exports within hosting capacity limits provides a means to ensure safe, reliable power to all customers and prevent equipment failure.

To expedite review of these systems through the SDP Amendment Process, the Company has an established Technical Review Process Flow Chart in Rule 14H, which is designed to quickly enable systems posing no risk to the grid, and provides for incremental steps (or screening) to review the applicant's system should there be mitigations required.

In general, the Technical Review Process Flow Chart (shown as Distribution Planning Review in Figure 1) will approve SDP projects in the following steps:

- Step 1 (Immediate Approval): Immediate approval is provided to systems:
  - which have existing interconnection agreements with the Company;
  - where export during the hours of 9:00 a.m. – 5:00 p.m. will remain unchanged; and
  - where maximum export of the system will be 5 kW or less during the scheduled dispatch hours.
- Step 2 (Initial Technical Review Screens 1-11[6]): Should the systems not comply with Step 1, the system will undergo an Initial Technical Review Screen.
- Step 3 (Supplemental Review Screens 12-13[7]): A Supplemental Review is required if the system fails the screens in Step 3. The Supplemental Review provides a more detailed review to understand the integration of the applicant's system relative to power quality,

[5] D&O 37816 at 27.
[6] *See* Technical Review Process Flow Chart, Rule 14H, Appendix III, Sheet No. 34D-8.
[7] *See* Technical Review Process Flow Chart, Rule 14H, Appendix III, Sheet No. 34D-8.

voltage fluctuation, safety, and reliability. Should the system fail this step, a grid upgrade or modification may be required to mitigate specific impacts.

The figures below map the steps explained above for existing and new customers. As discussed earlier, SDP enrollment will be through an amendment to customers' existing DER interconnection agreements. A new customer will go through a normal DER installation process first and then submit a follow-up request regarding their enrollment into SDP. The customer will have an opportunity to notify the Company in the normal DER process that they are interested in participating in the SDP program.

As discussed in the Implementation Plan and Schedule section, this process will be managed via CIT when the module is available, and until then it will be a manual process.

Figure 1: SDP Approval Process – Existing Customers

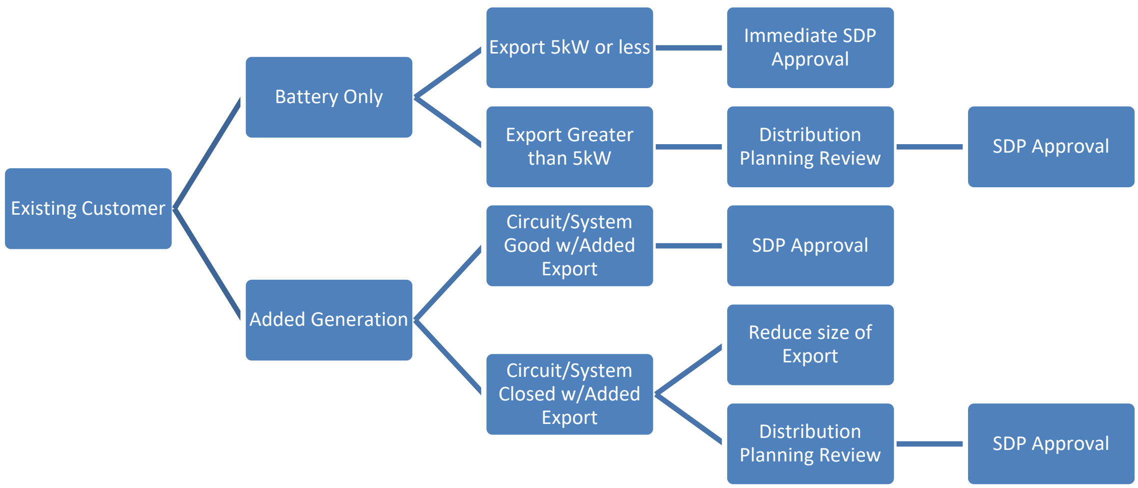


Figure 2: SDP Approval Process – New Customers

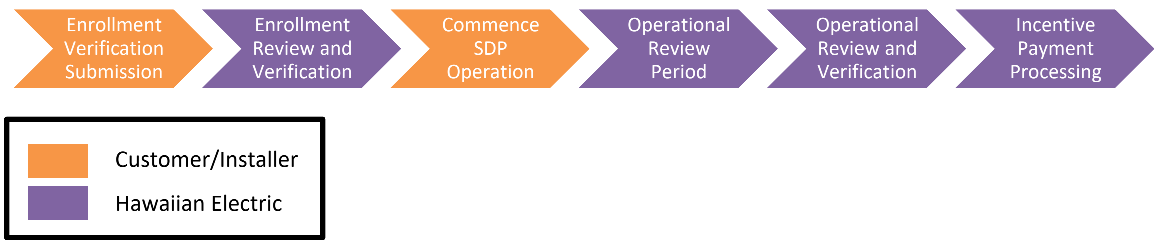
SDP Enrollment and Maintenance Process

After SDP is approved for enrollment through the SDP Amendment Process, the SDP enrollment process may be initiated to begin program participation. The processes presented here identify the fundamental steps required for SDP enrollment and maintenance. Many details of the processes are still under consideration and development, e.g., formats or form of specific submissions, calculation methodologies and tools, etc. The Company proposes the SDP Amendment approval date to be the date that also represents when that customer's incentive level is secured or locked-in, e.g., if enrollment is less than 15 MW, that customer will lock-in an $850/kW incentive rate.

SDP Enrollment Process

The SDP enrollment process begins after the customer has completed the SDP Amendment Process as outlined above and received approval for SDP participation. The figure below depicts the processes required to complete SDP enrollment.

Figure 3: SDP Enrollment Process



After installation is complete, the Customer Battery Storage Operator will notify the Company through CIT or email (interim) that they are ready to begin participation in SDP. Customer responsibilities under the SDP enrollment process are specified in section 5 and 7 of the SDP agreement. Additional information on each SDP enrollment phase is described below:

Enrollment Verification Submission. The customer or installer will provide documentation for Company review to, among other things, ensure the operation of the battery storage system is in compliance with SDP operational requirements. The Company understands that different battery storage system interfaces are unique but expects that screenshots will be sufficient to demonstrate compliance. At this time, if it has not already been provided, an SDP agreement executed by the customer must be submitted to the Company. In addition, the customer must provide their tax identification number ("TIN") as further discussed below in the Incentive Payment section. This data will be transferred via secure file transfer, and data will be handled as specified in section 11 of the SDP agreement.

Enrollment Review and Verification. The Company will complete the verification review within five (5) business days. Initially, submissions will be checked for completeness and incomplete submissions will be rejected. The Company will review at a minimum, committed capacity, evidence of compliance with the discharge window and duration, and TIN.

Commence SDP Operation. The customer will be notified of approval of verification of SDP operation. At this time, the customer can begin scheduled discharge and is enrolled in SDP. The date of approval of verification is also the commencement of service date or the enrollment start date.

Operational Review Period. The operational review period is thirty days from the enrollment start date. The purpose of the operational review period is to provide SDP participants the opportunity to tune SDP performance and prove compliance with the committed capacity. The SDP participant must provide performance data for at least fourteen consecutive days during the operational review period and notify the Company at the time it is submitted.

Operational Review and Verification. After receiving performance data gathered during the operational review period, the Company will review the data within ten business days. The Company will verify SDP performance using the following metrics:

1. Committed capacity is discharged and maintained for the two-hour period.
2. Committed capacity is discharged at the assigned start time for the two-hour period.

Compliance with these metrics must be demonstrated for ten consecutive days with discharge of the battery storage system achieving at least 95% of the committed capacity each day. If SDP performance does not comply with SDP operational requirements, the Company will notify the SDP participant. The SDP participant may remediate and enter another operational review period. If the Company does not notify the SDP participant within fifteen business days of submission of performance data, the SDP participant's operation is deemed to be automatically verified.

<u>Incentive Payment Processing.</u> Within approximately thirty days of operational verification, the SDP participant will receive a check enclosed with their bill for the incentive payment secured at their SDP amendment approval date for the committed capacity verified from the operational review and verification step.

The incentive payment is considered income by the IRS, and as such, the Company must provide SDP participants with 1099 forms and submit this income information to the IRS. To prepare the 1099 forms and submit participant income information to the IRS, the participants must provide their TIN to the Company (which is required prior to commencement of SDP operation). Section 11 of the SDP agreement specifically requires SDP participants to provide this information while also providing the Company's commitment to secure participants' data.

Queue Position and Incentive Rate Lock-in

Customers secure their "queue" position at their SDP amendment approval date. For SDP, the "queue" position represents the dollar per kW rate at which SDP participants will be compensated for their enrollment. At the SDP participant's enrollment start date, kW within the available step or tier will be allocated to them, which will "lock-in" their incentive rate. The Company will monitor this requirement closely and propose any adjustments if necessary in the future.

The Company contemplated aligning "queue" position to enrollment start date which ensures that SDP participants who are first to operation secure the greatest benefit available at that time. In addition, relying on enrollment start date provides additional incentive to potential SDP participants to proceed to operation as fast as possible, which in turn helps ensure that significant SDP is available and operational to fulfill any potential shortfall in 2022. However, after discussion with the DER Parties, the Company has accepted their position that customers should have assurance on the amount of their incentive as early as possible.

From previous experience, the Company notes that it is difficult to meet specific MW targets exactly "on the nose." As a result, the Company anticipates that when closing a MW tier in SDP, enrollment levels may be slightly above or below the limit due to allocation of kWs prior to operational verification, and amendments and withdrawals that typically occur in the interconnection process. Any variance will be trued-up at closing of the SDP enrollment phase by slightly under-enrolling or over-enrolling the final 20 MW to stay within the approved program budget.

Any SDP participants in the queue as of December 31, 2023, will be removed and notified of their removal.

Maintenance – Performance Audit

The Company will continue to monitor the performance of each SDP participant's battery storage system in accordance with the operational requirements under which they were enrolled. Currently, the Company is developing processes and tools for performing performance audits, including investigating leveraging Grid Modernization infrastructure to assist in monitoring customer meters to flag consumption or export anomalies that may indicate a performance issue. In accordance with the process specified in D&O 37816,[8] the Company will provide seven (7) day advance notification of audit to SDP participants. The audit process will likely require the Company to request SDP operational data for a specified period, e.g., 10-20 days to be provided by the SDP participant. SDP operational data may include battery discharge kW and kWh. The Company will audit SDP operational data in concert with meter data. If the results of the analysis show that operational performance is below committed capacity, a failure to perform notification will be issued and the SDP participant will have thirty days to cure non-compliance. The Company may perform a second audit after remediation to ensure SDP operation is back in compliance. A penalty of up to $100/month to the customer or the DER system owner will start on the cure date if the second audit shows continued performance is not in compliance. The penalty will continue until non-compliance is remedied or the upfront incentive is returned based on a pro-rated amount of the remaining portion of the ten-year commitment. Section 7 of the SDP agreement outlines these failure to perform requirements. The collection of penalty will recorded as Other Operating Revenue in the Company's accounting treatment.

Enrollment Termination

The SDP participant may terminate their enrollment with sixty (60) days written notice. If termination occurs prior to completion of their ten-year commitment, the SDP participant is required to return a prorated portion of the incentive they received after operational verification. As stated in section 6 of the SDP agreement, the prorated portion is based on the remaining portion of the ten-year commitment from the date of termination. Participants may either pay in full or make other arrangement with the Company prior to termination. In addition, the SDP agreement may not be assigned to another party without written consent of the other parties as stated in section 17.c of the SDP agreement.

Education and Marketing

As the program launches on July 1, 2021, the Company will focus its attention on education and marketing to ensure SDP information is reaching all interested customers, solar contractors, and stakeholders. In the Company's experience, short notice and introduction to a new program may cause confusion and potentially delay the uptake of applications. Furthermore, the Company believes proper education to all solar contractors, i.e., beyond active members to the DER Docket, establishes a fair and level playing field to the industry and only bolsters the potential for the program to succeed. This step for outreach is important as the SDP incentive has a step-down tiered approach where there is clear benefit to be an early adopter of the program. The program is also available to commercial customers, and therefore, the Company will engage Key Account Managers to ensure that their commercial customers are aware of the new opportunity available from SDP.

From this filing of the Implementation Plan to July 1, 2021, the Company will focus on preparation of education and marketing materials such as:

1. Explanatory pages on www.hawaiianelectric.com

[8] *See* D&O 37816 at 28-29.

2. "One-page," customer-friendly explanation in PDF form linked to the Company's webpage
3. FAQ write up for customers in PDF form linked to the Company's webpage
4. More detailed contractor-friendly explanation in a PDF
5. Internal FAQ document for the Company's call center, and other customer-facing departments

Upon program launch on July 1st, the Company will utilize the developed material to actively outreach to customers, solar contractors, and stakeholders, and notify them that the SDP program will start accepting applications on August 1, 2021. The education and marketing tasks that will be considered are:

1. Advance detailed notice to the solar industry through a contractor email blast, at least a few days before general announcement, with links to information on Hawaiian Electric's website and offer a future date and time for contractors to participate in webinar/Q&A session with Hawaiian Electric. This will be an opportunity to outline the benefits of the program for contractors so that they will have the information they need to generate customer participation.
2. News release announcing Emergency DR / Scheduled Dispatch Program distributed to all media
3. News release posted on www.hawaiianelectric.com and shared via Hawaiian Electric mobile app, Facebook (136,757 followers), Twitter (63,616 followers) and Instagram (13,675 followers) to raise awareness
4. Earned media, including Think Tech appearance, and other appearances as available (morning TV shows)
5. Articles in Ho'oku'i, Small Business Central newsletter, and Medium blog
6. Email blasts to existing CER customer lists, leveraging links to the website
7. Promotion via Key Account Managers, and Government Relations emails to stakeholders
8. Follow-up as needed with contractors via email blast
9. Paid advertising as needed, including newspaper and digital ads

Cost Recovery

The Companies propose that the revenue requirements of the applicable incentive payments ($34,000,000), based on a ten-year amortization[9] that includes carrying costs[10] on the unamortized balance, would be recovered from customers through the DSM Surcharge. Exhibit 5 provides an illustrative estimate of SDP kW enrolled and the illustrative timing and associated incentive payments made to residential and commercial customers.

On a quarterly basis, the Companies will submit the total incentive amounts paid to customers for the respective quarter which will be recorded as deferred cost and request cost recovery over ten-years through the DSM surcharge. The Companies also propose carrying cost at the Allowance for Funds Used During Construction ("AFUDC") rate on net unamortized balance, and recovery of such costs. The costs (including accrued AFUDC) will be amortized over ten-year to the appropriate operations and maintenance expense account(s). The Companies propose a ten-year amortization to align with the Commission's order and the customer's program contract agreement.

[9] *See* D&O 37816 at 33.

[10] Given the 10-year amortization period instructed by the Commission, the Company proposes to include carrying costs in the EDR cost recovery through the DSM surcharge. Carrying costs are calculated in a manner consistent with the application of carrying costs at the AFUDC rate for deferred DRMS costs recovered via the REIP surcharge in Docket No. 2015-0411.

Exhibit 5 provides quarterly illustrative revenue requirements based on the ten-year amortization of incentive payments and inclusion of carrying costs on the unamortized balance, which drive the estimated residential and commercial DSM rate impacts and residential bill impacts. The Companies note that the carrying costs are applied throughout the ten-year amortization period, but for illustrative purposes have only been provided through Q4 2023. From the Exhibit 5 illustration, the 3-year average bill impact for a residential customer at 500 kWh would be an increase of approximately $1.37/month.

Program Evaluation and Reporting

After the SDP program is fully automated via CIT, the Company offers to post on its website bi-monthly the amount of kWs operational under the SDP, i.e., participants who are currently performing scheduled dispatch, presented by step-down incentive tiers and the number of kWs currently requesting enrollment. For example, the Company would post on its website data representing current and pending enrolled kW in the EDRP as of the 1st and 15th of the month to be updated on the 6th and the 21st or the next business day if the 6th or the 21st of the month falls on a weekend or on a Company holiday.

As discussed above, the Company is proposing cost recovery via the DSM Surcharge and anticipates submitting a separate quarterly report on the EDR Program in conjunction with the quarterly DSM surcharge filing.[11] The Company would like to use this filing opportunity to provide further transparency on the operation of the SDP to inform the Commission of any issues or process changes that may be required. Pending any lessons learned, the Company may use this filing to request an amendment to the program to further streamline the process.

Exhibits

The following exhibits are provided in support of this EDR/SDP Implementation Plan:[12]

- Exhibit 1: Proposed Rule 31, EDRP Tariff and SDP Rider
- Exhibit 2: Proposed Amendments to Rule 14H, Appendix III, Interconnection Process Overview
- Exhibit 3: EDRP Amendment to Existing Agreement
- Exhibit 4: Proposed Rule 31, Appendix A, SDP Participant Agreement
- Exhibit 5: EDR Incentive Recovery – Illustrative DSM Surcharge Calculations

Next Steps

The Company appreciates and understands the Commission's directive to implement the EDRP on an urgent basis. That said, in implementing the EDRP, the Company seeks to ensure a program and process that results in an excellent customer experience that brings benefits and value to customers. To this end and to comply with D&O 37816, the Company plans to take the following next steps:

- The Company will continue to work with its contractor and Key Account Managers to identify potential customers for the Fast DR Program, with the objective of reaching the 7 MW capacity by adding 2.657 MW of capacity by the end of 2022.
- The Company will begin executing on the eight key milestones set forth in Table 3:

[11] *See Order No. 36467, (1) Approving the HECO Companies' Grid Service Purchase Agreement with Open Access Technology International; and (2) Approving the HECO Companies' Request for Revised DR Portfolio Cost Recovery Through the DSM Surcharge*, Ordering Paragraph 2 at 22, filed on August 9, 2019 in Docket No. 2007-0341.

[12] The proposed rules are for Hawaiian Electric Company, Inc.

Table 3: Company's Implementation Plan Milestones

Milestone	Completed Date
Stakeholder Meeting - SDP Process Overview	8/1/2021
Interim Go-Live (Manual)[a]	8/1/2021
Program Administration Updates	8/1/2021
SAP Updates	9/15/2021
Marketing & Education	9/30/2021
DRMS Updates	9/30/2021
SDP CIT Go-live	11/1/2021
Performance Requirement Process	2/28/2022

Note (a): The EDRP tariff will be effective as of July 1, 2021, and any new DER applications submitted during this time will be honored and accepted to participate in the SDP program.

- With respect to marketing and education, because the SDP represents a brand-new program, involving new requirements, incentives, payment arrangements, enrollment process (both mid-term through the CIT and interim through a paper Amendment Form), and verification process, the Company will initiate outreach to contractors and customers on the new program, and be ready for application intake on August 1, 2021.
- The Company proposes 2 MW/minute as the operational requirement to participate in the SDP, and will continue to work with the DER Parties to refine a workable ramping solution to deliver the 50 MW in the SDP.
- The Company will begin to set up regular reports on the EDRP both on its website and through quarterly reports in conjunction with quarterly DSM surcharge filings. The Company intends to use the quarterly reports, in part to inform the Commission of any issues, lessons learned, or process changes that may be required to improve the program.

The Company is committed to working with the Parties in this proceeding and the Commission throughout the term of the EDRP to address issues relating to implementation and management of the EDRP, and ensure a successful program that meets the objectives of D&O 37816.

<u>EXHIBIT 1</u>

Hawaiian Electric Company, Inc.

Proposed Rule No. 31

Emergency Demand Response Program

Rider: Scheduled Dispatch Program

Rule No. 31

Emergency Demand Response Program

Rider: Scheduled Dispatch Program

AVAILABILITY FOR CUSTOMER BATTERY STORAGE-OPERATORS

Emergency Demand Response Program (“EDRP”) participation is available to new and existing Eligible Customer Battery Storage-Operators who own and operate a battery storage system charged from the Eligible Customer Battery Storage-Operator’s solar generating facility under the Company’s Net Energy Metering, Customer Self-Supply, Customer Grid-Supply, Customer Grid-Supply Plus, Smart Export, or Standard Interconnection Agreement programs as described in Rule Nos. 18, 22, 23, 24, 25, and Rule 14H Appendix II, respectively (“Battery Storage Facility”).

Rule No. 31

Emergency Demand Response Program

Rider: Scheduled Dispatch Program

A. AVAILABILITY

Scheduled Dispatch Program ("SDP") participation is available to new and existing Eligible Customer Battery Storage-Operators who own and operate a battery storage system charged from the Eligible Customer Battery Storage-Operator's solar generating facility under the Company's Net Energy Metering, Customer Self-Supply, Customer Grid-Supply, Customer Grid-Supply Plus, Smart Export, or Standard Interconnection Agreement programs as described in Rule Nos. 18, 22, 23, 24, 25, and Rule 14H Appendix II, respectively ("Battery Storage Facility") where:

1. Eligible Customer Battery Storage-Operators execute the Scheduled Dispatch Program Agreement, provided as Appendix A of this Rule ("SDP Agreement"), memorializing their participation in SDP and specifying the Committed Capacity (defined below) of their Battery Storage Facility,
2. Existing Eligible Customer Battery Storage-Operators with an executed interconnection agreement may add up to 5 kVa of post inverter alternating current generation capacity in coordination with their battery installation by submitting an amendment to their existing interconnection agreement ("SDP Amendment"),
3. For any solar generation capacity added in coordination with a Battery Storage Facility, the Committed Capacity (defined below) must be at least twice the nominal power rating of the added solar generation capacity, and
4. Participation in SDP does not inhibit Eligible Customer Battery Storage-Operators from fulfilling performance commitments of other demand response programs if dual participation is feasible.

B. ENROLLMENT

1. SDP will begin enrollment on August 1, 2021 and enrollment will be available until total enrolled SDP capacity reaches 50 megawatts ("MW") or until June 20, 2023, whichever comes first, unless otherwise ordered by the Commission.

2. Enrollment in SDP is a ten-year commitment comprised of an initial phase ending for all participants on December 31, 2023 and a final phase commencing on January 1, 2024 and continuing for the remainder of the Eligible Customer Battery Storage-Operator’s ten-year commitment. During the final phase of their ten-year commitment, each Eligible Customer Battery Storage-Operator will have the option to (a) continue operating their Battery Storage Facility under the SDP pursuant to this Rule or (b) transition to an alternative dispatch program upon meeting the applicable eligibility requirements for such alternative program.
3. For purposes of initiating the Eligible Customer Battery Storage-Operator’s ten-year commitment under this Rule, the enrollment start date occurs upon the commencement of the discharge of Committed Capacity for the Dispatch Period in accordance with this Rule.
    a. Within 30 days of the enrollment start date, the Eligible Customer Battery Storage-Operator shall provide 14 consecutive days of operational performance data in five (5) minute intervals as necessary for the Company to verify the Eligible Customer Battery Storage-Operator's compliance with this Rule. The Company shall be required to complete such verification within 10 business days of the receipt of such performance data from Eligible Customer Battery Storage-Operator.
    b. If no requests for additional data or concerns are expressed regarding Committed Capacity or operation of the Battery Storage Facility as specified in section C of this Rule are communicated (in written or digital form) to the Eligible Customer Battery Storage-Operator by Company, the Eligible Customer Battery Storage-Operator will be deemed verified as operating in compliance with this Rule.

C. OPERATION

1. The Eligible Customer Battery Storage-Operator shall specify in its SDP Agreement the capacity level (kW) at which they commit to maintain the discharge level from their Battery Storage Facility (“Committed Capacity”) for a duration of two consecutive hours each day (“Dispatch Period”). The Dispatch Period will be specified by the Company at the time of enrollment and may be revised by the Company with reasonable notice.

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2. Energy discharged during the Dispatch Period from the Battery Storage Facility may either serve onsite load or be exported to the grid. The Eligible Customer Battery Storage-Operator shall be required to manage their Battery Storage Facility to automatically prioritize battery charging during periods of substantial solar panel insolation in order to most reliably serve the two-hour battery discharge commitment as scheduled by the Company.
3. Notwithstanding any other provision specified in the underlying program tariff in which the Eligible Customer Battery Storage-Operator participates or in the interconnection agreement to which the Eligible Customer Battery Storage-Operator is a party, as applicable, energy exported to the grid from the Battery Storage Facility for SDP during the Dispatch Period is permitted and, if applicable, compensated in accordance with the Eligible Customer Battery Storage-Operator's underlying program tariff.
4. Eligible Customer Battery Storage-Operator shall use the default ramp rate of equipment for the Committed Capacity during the Dispatch Period. Deviations from the default ramp rate may be required in certain circumstances where the default ramp rate may pose adverse impacts to grid power quality. The Company will notify the Eligible Customer Battery Storage-Operator of any such deviation when the Dispatch Period is specified or revised.

D. COMPENSATION

Participation in the SDP shall be compensated by a one-time incentive payment (“Incentive Payment”) based on the Battery Storage Facility’s demonstrated Committed Capacity for the Dispatch Period in accordance with this Rule. The Incentive Payment shall be determined as of the SDP Amendment approval date pursuant to the table below:

Total SDP Committed Capacity MW	Incentive Payment Rate
First 15 MW	$850/kW of Committed Capacity
Next 15 MW	$750/kW of Committed Capacity
Next 20 MW (not to exceed 50 MW in total)	$500/kW of Committed Capacity

1. The Eligible Customer Battery Storage-Operator must demonstrate compliance as described section B.3 with this Rule prior to receiving the Incentive Payment.
2. The Incentive Payment will be paid in full within 90 days of the date on which discharge of the Committed Capacity for the Discharge Period is demonstrated in compliance with this Rule. Payments shall be made directly to the owner of the Battery Storage Facility as identified in the SDR Agreement.
3. If the Eligible Customer Battery Storage-Operator does not operationalize its conditionally approved Battery Storage Facility by December 31, 2023, the Company will void the conditional approval to install and therefore will not owe the Eligible Customer Battery Storage-Operator any Incentive Payment.

E. FAILURE TO PERFORM

If the Company identifies concerns or issues relating to the Battery Storage Facility's performance, including, without limitation, potential non-compliance with this Rule pertaining to the discharge of Committed Capacity for the Discharge Period, the Company may conduct a performance audit to monitor and document conditions.

1. The Company shall provide the Eligible Customer Battery Storage-Operator written or digital notice at least seven (7) days in advance of any performance audit.
2. Eligible Customer Battery Storage-Operators are required to provide five (5) minute interval data as necessary to verify operation of SDP as specified in section C of this Rule within 5 business days of request from Company.
3. If the Battery Storage Facility fails to perform in compliance with this Rule, the Company will provide to the Eligible Customer Battery Storage-Operator a written notice of Failure to Perform, which will include documentation explaining the non-compliance of operation. The Eligible Customer Battery Storage-Operator will have 30 days from the date of such notice of Failure to Perform to cure the non-compliance.
4. If the non-compliance persists beyond the 30-day cure period, the Eligible Customer Battery Storage-Operator (recipient of the one-time Incentive Payment) may be charged up to $100 monthly until either the non-compliance is rectified or the Company has recovered the full prorated Incentive Payment amount.

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Emergency Demand Response Program

Rider: Scheduled Dispatch Program

F. TERMINATION

1. Notwithstanding their ten-year commitment under this Rule, the Eligible Customer Battery Storage-Operator may terminate, or a new account holder may assume, their SDP Agreement with written or digital notice provided 60 days prior to date of termination or assumption.
2. If termination occurs prior to completion of the ten-year commitment, the Eligible Customer Battery Storage-Operator shall return a prorated portion of the Incentive Payment received. The prorated portion shall be based on the remaining portion of the ten-year commitment, calculated from the date of termination as a fraction of the Eligible Customer Battery Storage-Operator's ten-year commitment.
3. The Company will bill the prorated amount to the Eligible Customer Battery Storage-Operator. The Eligible Customer Battery Storage-Operator may either pay in full or make other arrangements with the Company prior to termination. The Company will not charge interest on a payment if final payment is made within one year of date of termination. Eligible Customer Battery Storage-Operators that are not direct customers must pay prorated amount in full.

G. METERING AND BILLING

1. The Company will supply, install, own, and maintain all necessary meters and associated equipment utilized for billing, energy purchase, and performance auditing. The meters will be tested and read in accordance with the rules of the Commission and the Company.
2. Energy exported to the grid from the Battery Storage Facility will be compensated at applicable Energy Credit Rates for the Eligible Customer Battery Storage-Operator, as specified in the underlying program tariff in which the Eligible Customer Battery Storage-Operator participates.
3. All rates, terms, and conditions from the applicable rate schedule will apply, as modified by the Eligible Customer Battery Storage-Operator's applicable program tariff, if applicable.

EXHIBIT 2

Hawaiian Electric Company, Inc.

Proposed Amendments to

Rule No. 14H

Appendix III

Interconnection Process Overview

APPENDIX III
Interconnection Process Overview

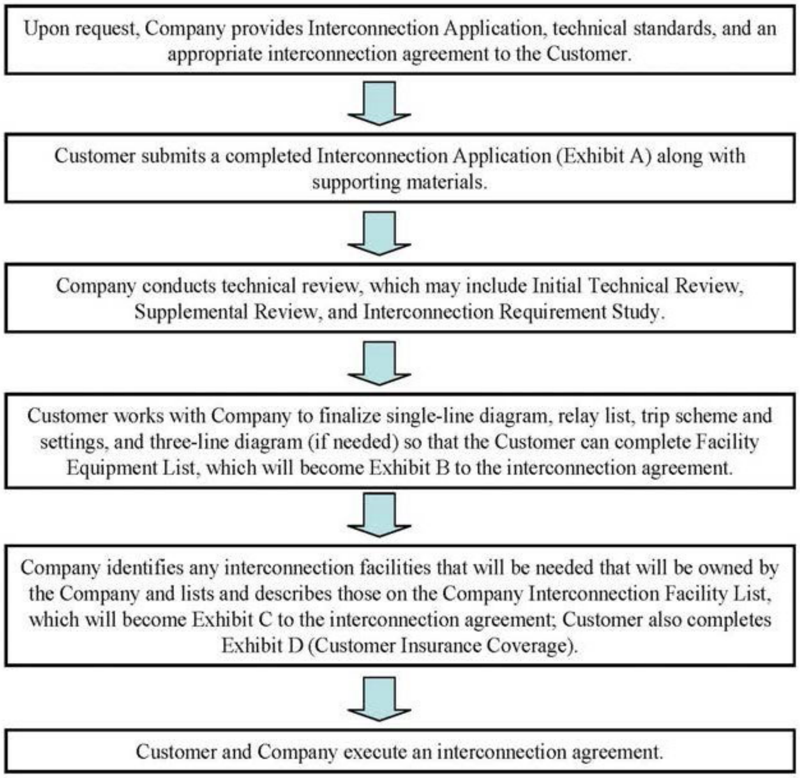
The purpose of this Appendix III is to provide a general overview of the process and procedures for interconnecting a Generating Facility that will operate in parallel with the Company's Distribution System. The general technical guidelines to facilitate the interconnection and parallel operation of Generating Facilities with the Company's Distribution System are set forth in Appendix I of this Rule 14H. For Generating Facilities subject to Rule 14H, if there is a conflict between the technical specifications set forth in Appendix I with any technical specifications set forth elsewhere in the Company's tariffs, the specifications of Appendix I shall prevail. Capitalized terms used in this Appendix III are defined in Appendix I of this Rule 14H.

1. <u>Steps in the Interconnection Process</u>

a. The interconnection process will be initiated when a Customer approaches or contacts the Company to request interconnection of a Generating Facility to the Company's Distribution System that will operate in parallel with the Company's Distribution System. The Company shall designate a centralized point of contact for applications to interconnect a Generating Facility to the Company's Distribution System.

b. The following flowchart provides, for illustrative purposes, the major steps in the interconnection process:

STEPS IN THE INTERCONNECTION PROCESS



c. The activities in each step shown in the flowchart are explained below:

Step 1: Within five (5) business days of receiving a Customer's request to interconnect a Generating Facility to the Company's Distribution System, the Company will provide the Customer with: (a) the Distributed Generating Facility Interconnection Standards Technical Requirements (Rule 14H Appendix I); (b) an appropriate interconnection agreement depending on the Customer's intent to export or participate in a wholesale power sale arrangement; and (c) this Interconnection Process Overview (Rule 14H Appendix III).

Step 2: The Company's interconnection review begins when a Customer submits a completed Exhibit A to Appendix II, Appendix II-A or Appendix II-B attached hereto or other Company-approved application for interconnection of a Generating Facility governed by

Rule 14H ("Interconnection Application").

For those Customers that apply to add a non-exporting system to their existing exporting system, such Customers shall provide the following to the Company, to the extent required to complete the Interconnection Application or otherwise requested by the Company in connection with its interconnection review: the Program System Size and Technical System Size of the existing (exporting) Generating Facility and the new Generating Facility (non-export) addition.

Along with the Customer's Interconnection Application, the Customer must also provide the design drawings, operating manuals, manufacturer's brochures/instruction manual and technical specifications, manufacturer's test reports, bill of material, protection and synchronizing relays and settings, and protection, synchronizing, and control schemes for the Generating Facility to the Company for its review. The Company shall have the right to specify the protection and synchronizing relays and settings, and protection, synchronizing and control schemes, consistent with the technical requirements of Appendix I, that affect the reliability and safety of operation and power quality of the Company's system with which the Generating Facility seeks to interconnect ("Facility Protection Devices/Schemes"). The Company shall maintain the confidentiality of information the Customer deems confidential, unless and until a final, non-appealable Commission decision determines that disclosure is necessary to protect the public or as otherwise determined by the Commission.

Within fifteen (15) business days of the receipt of an Interconnection Application and supporting material, or such other period as is mutually agreed upon in writing by the Company and the Customer, the Company shall review the Customer's Interconnection Application and supporting material and provide written notification of its general completeness, or alternatively, incompleteness. If an Interconnection Application is deemed incomplete, the Company shall specify in a written notice the additional information that is required. The completeness determination cycle will be repeated as necessary until sufficient information is submitted by the Customer to enable the Company to review the Interconnection Application.

Step 3: Within fifteen (15) business days of the date the Customer's Interconnection Application and supporting materials are deemed complete, the Company will complete an

Initial Technical Review of the Interconnection Application. The Company shall make a determination as to whether a Generating Facility is interconnected, designed to operate in parallel or designed to function with momentary parallel operation with the Company's electric system during the Initial Technical Review.[1] The Initial Technical Review will result in the Company providing either:

(1) Expedited Review for Self-Supply and NEM+ Systems: Interconnection Applications for Customer Self-Supply Systems under Company's Rule 22 (Customer Self- Supply) and NEM+ Systems comprised of more than a standalone energy storage system, e.g., battery storage, under Company's Rule 27 (NEM+) that will not export power across the Point of Interconnection except as allowed under Rule 22, Rule 27 and as required under this Rule 14H, shall qualify for expedited interconnection.

(2) Simplified Interconnection or Supplemental Review: For all Interconnection Applications, other than Appendix II-B, if all of the Initial Technical Review Screens are passed, the Generating Facility qualifies for Simplified Interconnection, and an executable interconnection agreement for the Customer's signature; or, if one or more screens are not passed, notification that Supplemental Review will be required and the results, in writing, of all Initial Technical Review screenings.

If Supplemental Review is required, the Customer shall notify the Company, in writing, to proceed with the Supplemental Review, or the Customer shall agree to withdraw its Interconnection Application. In order to expedite the process, Customer may pre-acknowledge

[1] **Momentary-Parallel Systems**: For Appendix II-B Applications, i.e. Application For Non-Export Distributed Generation Facilities (Momentary-Parallel Operation), if the Generating Facility is designed to operate in parallel with the Distribution System, for a duration of less than 0.1 seconds, i.e. "momentary parallel operation", then the Generating Facility qualifies for expedited interconnection. Registration shall satisfy the Customer's notice requirements set forth in Tariff Rule 3B (Change In Customer's Equipment Or Operations) and is required for purposes of determining potential load that the Company may be required to serve. Such systems shall be deemed to be "non-exporting" and shall not require reverse power protection. However, the Company may install at Company's expense, a bi-directional advanced meter. Company shall have the right to disconnect a Generating Facility without prior notice to the Customer pursuant to Rule 14H, Section 4.b, in the event the Company determines that the Generating Facility is operating in parallel with the Distribution System in excess of momentary parallel operation and Customer shall pay for any and all costs incurred by the Company in enforcing this right.

and agree to proceed to Supplemental Review, if necessary, at the time an Interconnection Application is submitted to the Company for review. Within twenty (20) business days of notification by the Customer that it would like to move forward with Supplemental Review, the Company shall complete a Supplemental Review. The Supplemental Review will result in the Company providing either: (a) Simplified Interconnection (b) interconnection requirements beyond those for a Simplified Interconnection, and a non-binding, good faith estimate of the Company's portion of the costs to perform the interconnection requirements identified by the Supplemental Review, or (c) a determination that an Interconnection Requirements Study (IRS) is required, and a good faith cost estimate and schedule for the completion of the IRS including an identification of the specific analysis and/or reviews that will be performed as part of the IRS.

If an IRS is required, the Customer shall agree to pay the cost estimate for the IRS provided by the Company, or the Customer shall withdraw its Interconnection Application. The Company shall complete the IRS within one hundred fifty (150) calendar days of the Customer's agreement to move forward with the IRS and payment of the IRS cost is received. The completion of the IRS shall include the Company's proposal to the Customer of the following: (a) interconnection requirements and a non-binding, good faith estimate of the Company's portion of the costs to perform the interconnection requirements; and (b) protection and synchronizing relays and settings, protection, synchronizing and control schemes, and any other equipment and/or performance requirements necessary to meet the IRS requirements.

Final results of all technical screenings, Supplemental Review, and IRS will be provided in writing to the Customer.

Step 4: Based on the results of the Initial Technical Review, or Supplemental Review (if needed), or IRS (if needed), the Customer and Company will work together to finalize the single-line diagram, relay list, trip scheme and settings, and three-line diagram, which is required in the circumstances set forth in the Interconnection Application. After finalization of the single-line diagram, relay list, trip scheme and settings, and three-line diagram (if required), the Customer will make any revisions deemed necessary to the Interconnection Application and resubmit the Interconnection Application to the Company. Resubmission will not impact the Customer's interconnection position. The Customer must also complete a Facility Equipment List, which will identify equipment, space and/or data at the Generating Facility location that must be provided by the Customer for use in conjunction with the Company's Interconnection Facilities. The Facility Equipment List will be included as Exhibit B to an interconnection agreement entered between the Company and the Customer. If requested, the Company will provide assistance to the Customer to complete the Facility Equipment List.

Step 5: Within fifteen (15) business days of the completion of all activities specified in Step 4 above, or within such other period as is mutually agreed upon in writing by the Company and the Customer, the Company will complete an identification of Interconnection Facilities that are necessary to complete the interconnection and that will be owned by the Company. A list and description of the Company's Interconnection Facilities will be included as Exhibit C to the interconnection agreement entered between the Company and the Customer. The Company and Customer shall mutually agree in writing to a schedule by which the Interconnection Facilities will be constructed and a determination of when the Customer's Generating Facility shall be connected to the Company's Distribution System. The Interconnection Facilities are project-specific, and the time to complete the facilities will depend on the complexity of the facilities required. Consistent with Section 5 of this Appendix III, the Customer shall maintain insurance coverage or be self-insured against risks arising under the interconnection agreement. The

Customer Insurance Coverage will be included as Exhibit D to any interconnection agreement entered between the Company and the Customer.

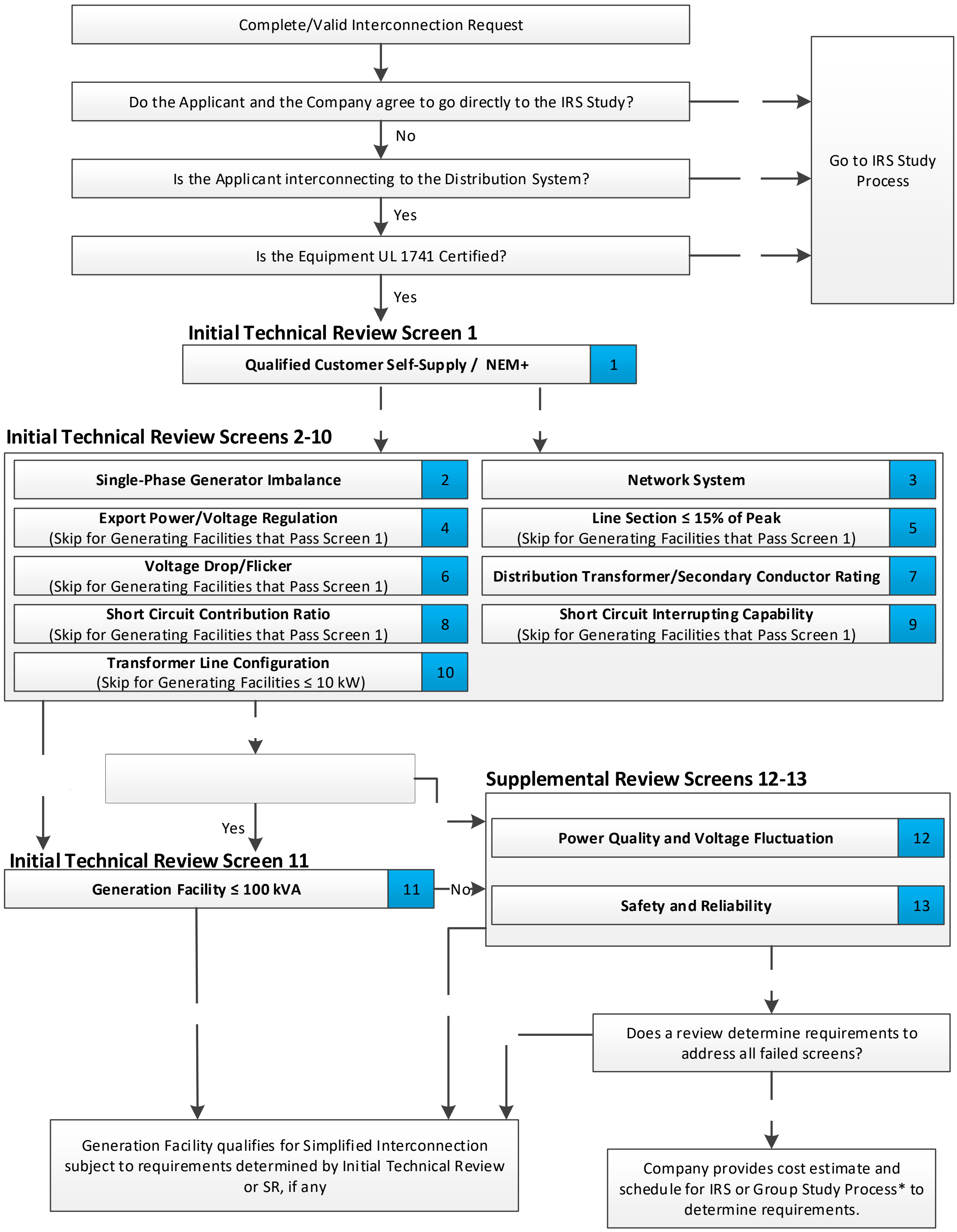
Step 6: Within five (5) business days of the completion of all activities specified in Step 5 above, the Company will provide the Customer with an executable interconnection agreement, which must be executed prior to the interconnection and parallel operation of the Customer's Generating Facility. If requested by the Customer, the interconnection agreement may be signed by the Customer and a third party that is the owner and/or operator of the Generating Facility.

The Company will provide a fully executed interconnection agreement to the Customer: (a) within fifteen (15) business days of receipt of Customer's executed interconnection agreement if all applicable City and/or County permits required for the Generating Facility have been closed and posted, and all Customer documentation required as a part of the interconnection agreement have been received; or (b) within fifteen (15) business days following the date upon which all applicable City and/or County permits required for the Generating Facility have been closed and posted, and all Customer documentation required as a part of the interconnection agreement have been received.

2. Overview of Technical Review Process

a. **Process Flowchart**: The following flowchart provides, for illustrative purposes, the major steps in the technical review process:

TECHNICAL REVIEW PROCESS FLOW CHART



* "Group Study Process" may include a consolidated IRS or a proactive utility determination of interconnection requirements covering multiple Generating Facilities.

b. **Explanation of Screens**: The following provides an explanation of the screens used in the technical review process:

Introduction:

The technical review process allows for the timely approval for the interconnection of Generating Facilities to the Company's Distribution System that will operate in parallel with the Company's Distribution System. The technical review process includes a screening to determine if a Generating Facility qualifies for Simplified Interconnection, or if Supplemental Review is needed to determine requirements, if any, beyond those of a Simplified Interconnection, or if an Interconnection Requirement Study (IRS) is needed to determine interconnection requirements. The Company will perform an Initial Technical Review unless (1) Applicant and the Company mutually agree to proceed directly to an IRS, (2) an Applicant is not connecting to the Company's Distribution System, or (3) an Applicant is interconnecting with equipment that is not UL 1741 certified, provided that the Company may permit uncertified equipment to proceed without an IRS if the equipment will provide benefits related to safety, reliability or power quality. If (1), (2), or (3) applies, the Applicant will proceed directly to an IRS.

Note: Failure to pass any screen of the Initial Technical Review process or Supplemental Review process means only that additional review is required to determine whether additional requirements, if any, are needed before the Generating Facility can be approved for interconnection with the Company's Distribution System. Although not explicitly covered in the review process, the Generation Facility shall be designed to meet all of the applicable requirements in Appendix I of Rule 14H.

Purpose:

The technical review process determines the following:

1) If a Generating Facility qualifies for Simplified Interconnection,

2) If a Generating Facility can be made to qualify for interconnection by performing a Supplemental Review that will be able to determine additional requirements, if any,

3) If an IRS is required, the cost estimates and rough schedule for performing the IRS, or

<u>Initial Technical Review Screens (Screens 1 through 11)</u>:

Screen 1: Does the proposed Generating Facility meet the Technical Specifications stated in Rule 22 (Customer Self-Supply), Appendix II, or Rule 27 (NEM+), Appendix III?

If Yes (Pass), continue to Screen 2, skip Screens 4, 5, 6, 8, and 9.

If No (Fail), continue to Screen 2.

<u>Significance</u>: 1) The Screen affords Expedited Review for qualified Customer Self-Supply Systems and NEM+ Systems.

<u>Note 1</u>: For a qualified Customer Self-Supply System or NEM+ System, the Company may install, at Company's expense, a bi-directional advanced meter.

<u>Note 2</u>: Any equipment for a qualified Customer Self-Supply System or NEM+ System shall be included by the Customer in the Facility Equipment List. Such equipment is intended to monitor and prevent an extended reverse power condition in which power flows from the Generating Facility to the Distribution System.

<u>Note 3</u>: The Company shall have the right to disconnect a Generating Facility without prior notice to the Customer pursuant to Rule 14H, Appendix I, Section 4.b in the event the Company determines that the Generating Facility is exporting power to the

Distribution System for longer than the allowable limit as defined in Rule 22, Appendix II, or in a manner inconsistent with the limits defined in Rule 27, Appendix III, as applicable, and Customer shall pay for any and all costs incurred by the Company in enforcing this right.

Screen 2: If the proposed Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, does it cause unacceptable imbalance between the two phases of the 240 volt service?

If Yes (Fail), continue to Screen 3; Initial Technical Review Screens 2 through 10 shall be completed in its entirety. If any of the Screens 2 through 10 are not passed, Company may perform a review of the failed Screen(s) during the Initial Technical Review period which may determine additional requirements needed to address the failure(s). Otherwise, Supplemental Review is required.

If No (Pass), continue to Screen 3.

Significance: Generating Facilities connected to a single-phase transformer with 120/240 V secondary voltage must be installed such that the aggregated gross output is as balanced as practicable between the two phases of the 240 volt service.

Screen 3: Is the Point of Interconnection to a Network System?

If Yes (Fail), continue to Screen 4; Initial Technical Review Screens 2 through 10 shall be completed in its entirety. If any of the Screens 2 through 10 are not passed, Company may perform a review of the failed Screen(s) during the Initial Technical Review period which may determine additional requirements needed to address the failed Screen(s). Otherwise, Supplemental Review is required.

If No (Pass), continue to Screen 4.

Docket No. 2014-0192, D&O No. 35746 dated October 12, 2018.
Transmittal Letter Dated October 22, 2018.

Significance: Special considerations must be given to Generating Facilities proposed to be installed on a Network System because of the design and operational aspects of network protectors. There are no such considerations for radial Distribution Systems.

Screen 4: If exporting power across the Point of Interconnection, can the power export cause a reversal of power flow, during normally expected circuit operating conditions, at any voltage regulation device that is not bi-directional?

If Yes (Fail), continue to Screen 5; Initial Technical Review Screens 2 through 10 shall be completed in its entirety. If any of the Screens 2 through 10 are not passed, Company may perform a review of the failed Screen(s) during the Initial Technical Review period which may determine additional requirements needed to address the failed Screen(s). Otherwise, Supplemental Review is required.

If No (Pass), continue to Screen 5.

Significance: If it can be assured that the Generating Facility will not export power, or if exported power will not cause a reversal of power flow at a voltage regulation device that is not designed to handle reverse power flow, the Company's Distribution System does not need to be studied for load-carrying capability or Generating Facility power flow effects on the Company's voltage regulators.

Note 1: This screen does not apply to a Generating Facility that passes Screen 1.

Note 2: The Technical System Size will be used in the evaluation of this Screen. However, if for example, the contribution of the energy storage system to the Technical System Size is limited by programming or by some other on-site limiting element, the reduced Technical System Size will be used in the evaluation of this Screen.

Screen 5: Is the aggregate Generating Facility capacity on the Line Section less than or equal to 15% of Line Section peak?

If Yes (Pass), continue to Screen 6.

If No (Fail), continue to Screen 6; Initial Technical Review Screens 2 through 10 shall be completed in its entirety. If any of the Screens 2 through 10 are not passed,Company may perform a review of the failed Screen(s) during the Initial Technical Review period which may determine additional requirements needed to address the failed Screen(s). Otherwise, Supplemental Review is required.

Significance: 1) Low penetration of Generating Facility installations should have a minimal impact on the operation and load restoration efforts of the Company's Distribution System.

2) The operating requirements for a high penetration of Generating Facilities may be different since the impact on the Company's Distribution System will no longer be minimal, therefore requiring additional study or controls.

Note 1: This screen does not apply to a Generating Facility that passes Screen 1.

Note 2: As applicable, the Technical System Size will be used in the evaluation of this Screen. However, if for example, the contribution of the energy storage system to the Technical System Size is limited by programming or by some other on-site limiting element, the reduced Technical System Size will be used in the evaluation of this Screen.

Screen 6: Is the voltage flicker and/or voltage drops associated with the Generating Facility within IEEE 519, IEEE 1453, or General Order 7 limits?

If Yes (Pass), continue to Screen 7.

If No (Fail), continue to Screen 7; Initial Technical Review Screens 2 through 10 shall be completed in its entirety. If any of the Screens 2 through 10 are not passed, Company may perform a review of the failed Screen(s) during the Initial Technical Review period which may determine additional requirements needed to address the failed Screen(s). Otherwise, Supplemental Review is required.

Significance: 1) This screen addresses potential voltage fluctuation problems for other customers on the distribution circuit caused by Generating Facilities, especially those that start by motoring.

2) When starting or connecting to the system, Generating Facilities should have minimal impact on the service voltage of other Customers.

3) This screen addresses voltage flicker at the Point of Interconnection caused by the Generating Facility. Passing this screen does not relieve the Customer from ensuring that its Generating Facility complies with the flicker requirements of Rule 14H.

Note 1: This screen does not apply to a Generating Facility that passes Screen 1.

Note 2: As applicable, the Technical System Size will be used in the evaluation of this Screen. However, if for example, the contribution of the energy storage system to the Technical System Size is limited by programming or by some other on-site limiting element, the reduced Technical System Size will be used in the evaluation of this Screen.

Note 3: Energy Storage Systems that are designed or operated to charge from the utility grid will be considered in this Screen. The maximum charging kW of the energy storage system will be used in the evaluation of this Screen.

Screen 7: Do the maximum aggregated gross ratings for all the Generating Facilities connected to a secondary distribution transformer exceed the transformer, secondary conductor, fuse, or other equipment rating, absent the Applicant's generators?

If Yes (Fail), continue to Screen 8; Initial Technical Review Screens 2 through 10 shall be completed in its entirety. If any of the Screens 2 through 10 are not passed, Company may perform a review of the failed Screen(s) during the Initial Technical Review period which may determine additional requirements needed to address the failed Screen(s). Otherwise, Supplemental Review is required.

If No (Pass), continue to Screen 8.

Significance: This screen addresses potential Distribution Transformer or secondary conductor, fuse, and/or other equipment overloads and steady state voltage issues.

Note 1: For a Generating Facility that passes Screen 1, the Generating Facility will be considered to have a net-zero load impact to the calculations performed as part of this screen (i.e. customer load will be offset by the qualified Customer Self-Supply System or NEM+ system).

Note 2: As applicable, the Technical System Size will be used in the evaluation of this Screen. However, if for example, the contribution of the energy storage system to the Technical System Size is limited by programming or by some other on-site limiting element, the reduced Technical System Size will be used in the evaluation of this Screen.

Note 3: Energy Storage Systems that are designed or operated to charge from the utility grid will be considered in this Screen. The maximum charging kW of the energy storage system will be used in the evaluation of this Screen.

Screen 8: Is the Short Circuit Current Contribution Ratio within acceptable limits?

If Yes (Pass), continue to Screen 9.

If No (Fail), continue to Screen 9; Initial Technical Review Screens 2 through 10 shall be completed in its entirety. If any of the Screens 2 through 10 are not passed, Company may perform a review of the failed Screen(s) during the Initial Technical Review period which may determine additional requirements needed to address the failed Screen(s). Otherwise, Supplemental Review is required.

Significance: When measured at the primary side (high side) of a Dedicated Distribution Transformer serving a Generating Facility, the sum of the short circuit contribution ratios of all generating facilities connected to the secondary side (low side) of that Distribution Transformer must be less than or equal to 0.1 (10%). If the Generating Facility passes this screen it can be expected that it will have no significant impact on the Company's Distribution System's short circuit duty, fault detection sensitivity, relay coordination or fuse-saving schemes.

Note 1: This screen does not apply to a Generating Facility that passes Screen 1.

Screen 9: Is the Short Circuit interrupting capability exceeded?

If Yes (Fail), continue to Screen 10; Initial Technical Review Screens 2 through 10 shall be completed in their entirety. If any of the Screens 2 through 10 are not passed, Company may perform a review of the failed Screen(s) during the Initial Technical Review period which may determine additional requirements needed to address the failed Screen(s). Otherwise, Supplemental Review is required.

If No (Pass), continue to Screen 10.

Significance: This Screen determines whether the Generating Facility, in aggregate with other generation on the distribution circuit, causes any distribution protective devices and equipment on the system to exceed 87.5% of their short circuit interrupting capability. If the Generating Facility passes this screen it can be expected that it will have no significant impact on the Customer's service equipment.

Note 1: This screen does not apply to a Generating Facility that passes Screen 1.

Screen 10: Is the Line Configuration Screen (see below) acceptable for Simplified Interconnection?

If Yes (Pass), continue to Screen 11.

If No (Fail), continue to Screen 11; Initial Technical Review Screens 2 through 10 shall be completed in its entirety. If any of the Screens 2 through 10 are not passed, Company may perform a review of the failed Screen(s) during the Initial Technical Review period which may determine additional requirements needed to address the failed Screen(s). Otherwise, Supplemental Review is required.

Line Configuration Screen: Identify primary distribution line configuration that will serve the Generating Facility. Based on the type of interconnection to be used for the Generating Facility, determine from the table below if the proposed Generating Facility passes the screen.

Table I

Primary Distribution Line Type Configuration	Type of Interconnection to be Made to Primary Distribution Line	Results/Criteria
Three-phase, three wire	Any type	Pass Screen
Three-phase, four wire	Single-phase, line-to-neutral	Pass Screen
Three-phase, four wire (For any line that has such a section OR mixed three wire and four wire)	All others	To pass, aggregate Generating Facility nameplate rating must be less than or equal to 10% of Line Section peak load

Significance: If the primary distribution line serving the Generating Facility is of a “three-wire” configuration, or if the Generating Facility’s distribution transformer is single-phase and connected in a line-to-neutral configuration, then there is no concern about overvoltages to the Company’s or other Customer’s equipment caused by loss of system neutral grounding during the operating time of the non-islanding protective function.

Note 1: This Screen does not apply to Generating Facilities with a Gross Rating of 10 kW or less.

Screen 11: Is the gross rating of the Generating Facility 100 kVA or less?

If Yes, the Generating Facility qualifies for Simplified Interconnection. Skip remaining screens.

If No, continue to Screen 12.

Significance: After meeting the requirements of the previous screens, this Generating Facility will likely have a reduced impact on the Company's Distribution System.

a. Within fifteen (15) business days of the date the Customer's Interconnection Application is deemed complete, the Company will complete the Initial Technical Review and notify the Customer of the results.

b. In the event that Supplemental Review would otherwise be triggered by a failure of Screens 1 through 11, Company may perform a review of the failed screen(s) during the Initial Technical Review period which may determine the additional requirements needed to address the failed screen(s) without the need for Supplemental Review. Otherwise, Supplemental Review is required. Some examples of requirements that may be available to address the failure of Screens 1 through 11 without the need for Supplemental Review include:

1. Replace an overloaded Distribution Transformer with a larger transformer.
2. Replace overloaded secondary conductors with larger conductor.

3. Installation of an appropriately sized grounding transformer or other means to effectively ground a generator.

4. Transformer load tap changer upgrades.

5. Modified voltage and frequency ride-through settings.

6. Active and reactive power requirements.

7. Determine if phase balancing on the transformer is possible with minimal review.

8. If possible without further study, check if the Generating Facility will actually overstress equipment.

c. If Company performs a review of failed Screen(s) 1 through 11 during the Initial Technical Review period and is able to determine the additional requirements needed to address the failed screen(s) and such additional requirements includes equipment, space and/or data at the Generating Facility location to be provided by the Customer for use in conjunction with the Company's Interconnection Facilities, then the Customer must also complete a Facility Equipment List, which will identify such equipment, space and/or data. The Facility Equipment List will be included as Exhibit B to any interconnection agreement entered between the Company and the Customer. If requested, the Company will provide assistance to the Customer to complete the Facility Equipment List. Company will provide a non-binding, good faith estimate of the Company's portion of the costs to perform the interconnection requirement that has been identified.

d. The Initial Technical Review will result in the Company providing either: (a) if all of the Initial Technical Review Screens are passed, the Generating Facility qualifies for Simplified Interconnection, and an executable interconnection agreement for the Customer's signature; or, (b) if one or more screens are not passed, notification whether Supplemental Review will be required and the results, in writing, of all Initial Technical Review screenings.

3. Supplemental Review

a. If a Generating Facility has failed to meet one or more of the Initial Technical Review screens for Simplified Interconnection as proposed, and a review of the failed screen(s) cannot determine the requirement(s) to address the failure(s), then the Company will notify the Customer upon completing Initial Technical Review that a Supplemental Review as described in this section is needed.

b. If Supplemental Review is required, the Customer shall notify the Company, in writing, to proceed with the Supplemental Review, or the Customer shall agree to withdraw the Interconnection Application. If the Customer does not notify the Company within fifteen (15) business days, the Interconnection Application shall be deemed to be withdrawn.

c. The Supplemental Review shall be completed, absent any extraordinary circumstances, within twenty (20) business days of receipt of the Customer's approval, in writing, to proceed with the Supplemental Review. The Company, for good cause, without extraordinary circumstances, may modify the time limits to conduct the Supplemental Review and shall inform the Customer in writing of the need to modify the applicable time limits. The modified time limit shall be mutually agreed upon in writing between the Company and the Customer.

d. The Supplemental Review will result in the Company providing either: (a) Simplified Interconnection, (b) interconnection requirements beyond those for a Simplified Interconnection, and a non-binding, good faith estimate of the Company's portion of the costs to perform the interconnection requirements identified by the Supplemental Review, or (c) a determination that an IRS is required and a good faith cost estimate and schedule for the completion of the IRS, including an identification of the specific analysis and/or reviews that will be performed as part of the IRS.

e. The Supplemental Review consists of Screens 12 and 13. If any of the Screens are not passed, a review of the failed Screen(s) within the timeframe established for Supplemental Review, or any modified time limits, may determine interconnection requirements or special design or operating requirements of the Generating Facility to address the failure(s), in which case an IRS may not be necessary. Otherwise, an IRS is required. Some examples of requirements that may be available to address the failure of Screens 12 and 13 without the need for an IRS include:

1. Replacing a fixed capacitor bank with a switched capacitor bank.
2. Adjustment of line regulation settings.
3. Reconfiguration of the distribution circuit.
4. A modified operating schedule of the Generating Facility.
5. Additional technical requirements of the Generating Facility equipment.

Supplemental Review Screens (Screens 12 – 13):

Screen 12 (Power Quality and Voltage Tests): In aggregate with existing generation on the Line Section,

a) Can it be determined within the Supplemental Review that the voltage can be maintained in compliance with General Order 7?

b) Can it be determined within the Supplemental Review that the voltage fluctuation is within acceptable limits as defined by IEEE 1453 or utility practice similar to IEEE 1453?

c) Can it be determined within the Supplemental Review that the harmonic levels meet IEEE 519 limits at the point of interconnection?

If Yes to all (Pass), continue to Screen 13.

If No (Fail), a review of the failure may determine the additional requirements needed to address the failure; Continue to Screen 13.

Significance: Adverse voltages and undesirable interference may be experienced by other customers on the Company's Distribution System caused by operation of the Generating Facility.

Screen 13 (Safety and Reliability Tests): Does the location of the proposed Generating Facility or the aggregate generation capacity on the Line Section create impacts to safety or reliability that cannot be adequately addressed without an IRS?

If Yes (Pass), a review of the failure during the Supplemental Review may determine the requirements to address the failure, e.g. a Customer Self-Supply System that complies with the Technical Specifications stated in Company Rule 22 (Customer Self-Supply); otherwise, an IRS is required.

If No (Fail), Supplemental Review is complete.

Significance: In the safety and reliability test, there are several factors that may affect the nature and performance of an interconnection. These include, but are not limited to:

1. Generation energy source
2. Modes of synchronization
3. Unique system topology
4. Possible impacts to critical load customers
5. Possible safety impacts

The specific combination of these factors will determine if any system study requirements are needed. The following are some examples of the items that may be considered under this screen:

1. Does the Line Section have significant minimum loading levels dominated by a small number of customers (*i.e.*, several large commercial customers)?
2. Is there an even or uneven distribution of loading along the feeder?
3. Is the proposed Generating Facility located in close proximity to the substation (i.e. <2.5 electrical line miles), and is the distribution line from the substation to the customer composed of large conductor/cable (*i.e.*, 600A class cable)?
4. Does the Generating Facility incorporate a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time?
5. Is operational flexibility reduced by the proposed Generating Facility, such that transfer of the Line Section(s) of the Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues?
6. Does the Generating Facility utilize certified anti-islanding functions and equipment?

f. The Supplemental Review shall be completed within twenty (20) business days of completion of Initial Technical Review.

e. If the Supplemental Review results in interconnection requirements beyond those for a Simplified Interconnection, the Customer must also complete a Facility Equipment List, which will identify equipment, space and/or data at the Generating Facility location to be provided by the Customer for use in conjunction with the Company's Interconnection Facilities. The Facility Equipment List will be included as an Exhibit to any interconnection agreement entered between the Company and the Customer. If requested, the Company will provide assistance to the Customer to complete the Facility Equipment List.

4. Interconnection Requirements Study ("IRS")

If the Supplemental Review process fails to determine interconnection requirements, then an IRS shall be performed as follows:

a. If an IRS is necessary, the Company will provide the Customer with a good faith cost estimate and schedule for the completion of the IRS including an identification of the specific analysis and/or reviews that will be performed as part of the IRS. A cost estimate and schedule for the analyses will be provided to the Customer before the overall study is started. This generally would be done when the Company responds to the Customer with the findings of the Supplemental Review.

b. If an IRS is required, the Customer shall agree to pay the cost estimate for the IRS provided by the Company, or the Customer shall withdraw its Interconnection Application. If the Customer does not agree to perform an IRS or agree to pay the cost estimate for the IRS within fifteen (15) business days, the Interconnection Application shall be deemed to be withdrawn. Customers with existing Generating Facilities already operating in parallel with the Company's system on March 21, 2003, will not be charged for any IRS.

c. The scope and cost of the IRS will depend on the complexity of the Company's Distribution System to which the Generating Facility is requesting to interconnect, which must be modeled, and the degree to which the Generating Facility will affect the Company's system. Examples of the analyses and/or reviews that fall within an IRS include: (1) Feeder Load Flow; (2) Dynamic Stability Analysis; (3) Transient Overvoltage; and (4) Short Circuit and Relay Coordination.

d. The Company may perform the analyses included in the IRS. The Company may also contract the analyses or parts of the analyses to an outside consultant specializing in such analyses for complex situations, or in situations where the Company does not have available resources to conduct the analyses in a time frame mutually agreeable to both the Company and the Customer.

e. The Company shall complete or have a consultant complete the IRS within one hundred fifty (150) calendar days of the Customer's payment of the IRS. The Company, for good cause, without extraordinary circumstances, may modify the time limits to conduct the IRS and shall inform the Customer in writing of the need to modify the applicable time limit. The modified time limit shall be mutually agreed upon in writing between the Company and the Customer. The Company, shall provide a written letter to the Customer to explain all delays in completing the IRS beyond the completion schedule of one hundred fifty (150) calendar days.

f. The Customer and Company may agree (to be documented in writing) to have the IRS performed by a qualified third-party consultant, or by a qualified employee, contractor, or agent of the Customer at the Customer's sole cost so long as the employee, consultant, contractor, or agent meets the following qualifications: (1) experience and familiarity with electric utility system modeling, feeder load flow analyses, dynamic stability analyses, transient overvoltage analyses, and short circuit and relay coordination; (2) knowledge of electric utility system operation, transmission and distribution system planning and protection, and distributed generation interconnection issues; and (3) knowledge of the unique characteristics and needs of small, non-interconnected island electric grids and the unique challenges and operational requirements of such systems. In addition, the scope of work of the third-party consultant's study shall be mutually agreeable to both the Company and the Customer. Elements of the study scope of work may include items such as: (1) Feeder Load Flow; (2) Dynamic Stability Analysis; (3) Transient Overvoltage; and (4) Short Circuit and Relay Coordination. All study recommendations by the Customer's consultant shall be reviewed and approved by the Company.

g. The Company may consolidate more than one Generating Facility in an IRS if the Generating Facilities are on the same Distribution System feeder that is the subject of the IRS, provided that the Customers consent to consolidation and the sharing of technical information between them. Parties to a consolidated IRS shall pay study and upgrade costs on a pro rata basis as agreed by the parties that desire to share the costs for the IRS. The cost may be prorated based upon the expected annual electricity output of the respective facilities or the capacity of the Generating Facility.

h. The IRS may identify the need for Company Interconnection Facilities required to facilitate interconnection of the Generating Facility. The Customer will be responsible for the cost of any Company Interconnection Facilities associated with the interconnection of its Generating Facility. An identification of the Company Interconnection Facilities and an estimated cost of the Company Interconnection Facilities shall be listed in Exhibit C (Interconnection Facilities Owned by the Company) to the interconnection agreement entered between the Company and the Customer. The Customer will be responsible for the cost of any Company Interconnection Facilities associated with the interconnection of its Generating Facility.

i. If the Company determines that there are benefits to the utility system due to the Company Interconnection Facilities, a credit reflecting these benefits shall be provided to the Customer, subject to Commission approval. For example, if there is a planned Distribution System addition that may be deferred or displaced due to the addition of the Company Interconnection Facilities associated with interconnection of a Generating Facility, the dollar value of the deferral or displacement would be determined and proposed to be credited to the Customer (subject to Hawaii Public Utility Commission's approval) as a line item in Exhibit C to the interconnection agreement (Interconnection Facilities Owned by the Company), Section 2 (Customer Payment to Company for Company Interconnection Facilities, Review of Facility, and Review of Verification Testing). The calculation of the benefits to the utility system will be examined on a case-by-case basis taking into account what Distribution System addition(s) would have been deferred or displaced by the Company Interconnection Facilities that resulted from the interconnection of a Generation Facility. The Company would then calculate a dollar value of the deferral or displacement, and propose to credit the Customer for that deferral or displacement value. The Company shall file a letter providing the Commission with sufficient information to document the proposed credit to be provided to the Customer for said deferral or displacement value. The proposed deferral or displacement value would not be credited to the Customer until the Commission approves such credit.

5. Insurance Coverage

a. In accordance with Commission Decision and Order No. 22248, Docket No. 03-0371, the Company will not impose a standardized insurance requirement for distributed generation projects. However, the Customer is obligated to carry adequate insurance in forms and amounts that are commercially reasonable for each particular situation. The Customer bears responsibility for determining its insurance requirements. Prior to execution of the standard interconnection agreement, the Customer shall disclose if it will be self-insured (and if so its means and capability to self-insure) or if it will obtain an insurance policy (and if so in what forms and amounts). The Customer shall provide evidence of such insurance, including insurer's acknowledgement that coverage applies with respect to the standard interconnection agreement, by providing certificates of insurance to the Company prior to any parallel interconnection, or, if insurance is being modified, within 30 days of any change.

b. As general guidance, the Company recommends consideration of a commercial general liability policy, covering bodily injury and property damage. The Company also recommends that coverage amounts be considered relative to the nameplate rating of the generator, with higher amounts of coverage for larger generators. Additionally, the Company recommends consideration of the following insurance provisions: (1) naming the Company, its directors, officers, agents, and employees as additional insureds; (2) inclusion of contractual liability coverage for written contracts and agreements including the standard interconnection agreement; (3) inclusion of provisions stating that the insurance will respond to claims or suits by additional insureds against the Customer or any other insured thereunder; and (4) inclusion of provisions that the insurance is primary with respect to the Customer and the Company. The adequacy of the coverage afforded by the insurance should be reviewed by the Customer from time to time, and if it appears in such review that risk exposures require an increase in the coverages and/or limits of this insurance, the Customer should make such increase to that extent.

6. Resolution of Disputes

a. If there is a dispute between the Customer and the Company as to whether an IRS is required, or as to the scope and cost of the study, then the Company generally would use the following procedures: (1) the Company's Contact Person would inform the Customer of the reasons for and scope of the study required; (2) if the Customer disagrees with the conclusion, then the Customer would meet with representatives from the Company to discuss the matter; (3) if the Customer continues to disagree with the conclusion, then the Customer would write to the Company's Contact Person explaining the position of the Customer, and the Company's Contact

Person would respond in writing within fifteen (15) business days[2] (so that any dispute is reduced to writing); (4) if the parties continue to have a dispute, then authorized representatives from the Company and Customer (having full authority to settle the dispute) would meet in Hawaii (or by telephone conference) with the meeting to be scheduled within fifteen (15) business days of a written request and attempt in good faith to resolve the dispute; and (5) if the parties continue to have a dispute, then the parties may engage in a form of alternative dispute resolution agreeable to both parties, or a party may request that the Commission resolve the matter by filing a written request with the Commission attaching the relevant information and correspondence, and serving the request on the other party and the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs of the State of Hawaii.

b. If there is a dispute as to the need for interconnection equipment, protective devices or control systems, then the Company generally would use the following procedures: (1) the Company's Contact Person would inform the Customer of the reasons for the interconnection equipment/protective devices/control systems; (2) if the Customer disagrees with the conclusion, then the Customer would meet with representatives from the Company to discuss the matter; (3) additional analyses may be conducted by the Company at the request of a Customer that questions the need for particular interconnection equipment/protective devices/control systems if the Customer pays for the analyses; (4) if the Customer continues to disagree with the conclusion, then the Customer would write to the Company's Contact Person explaining the position of the Customer, and the Company's Contact Person would respond in writing within

[2] The Company, for good cause, may modify the time limit. If the Company modifies the time limit, it shall notify the Customer in writing of the modification and the cause for the modification.

fifteen (15) business days[3] (so that any dispute is reduced to writing); (5) if the parties continue to have a dispute, then authorized representatives from the Company and Customer (having full authority to settle the dispute), would meet in Hawaii (or by telephone conference) with the meeting to be scheduled within fifteen (15) business days of a written request and attempt in good faith to resolve the dispute; and (6) if the parties continue to have a dispute, then the parties may engage in a form of alternative dispute resolution agreeable to both parties, or a party may request that the Commission resolve the matter by filing a written request with the Commission attaching the relevant information and correspondence, and serving the request on the other party and the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs of the State of Hawaii.

c. Customers are not required to exhaust the Company's dispute resolution procedures set forth above before proceeding under provisions applicable to informal or formal complaints or other provisions contained under the Rules of Practice and Procedure before the Public Utilities Commission, currently codified in Title 6, Chapter 61, Subchapter 5 of the Hawaii Administrative Rules, or any other applicable statutes, orders, rules, or regulations. If any such proceeding is initiated, the Customer shall notify the Company's Contact Person in writing that it does not desire to continue the Company's dispute resolution procedures.

[3] The Company, for good cause, may modify the time limit. If the Company modifies the time limit, it shall notify the Customer in writing of the modification and the cause for the modification.

7. Modifications to Interconnection Applications

a. The provisions of this Section 7 shall apply only to those Customer Interconnection Applications for Generating Facilities under a Commission-approved DER program.

b. With respect to each Interconnection Application submitted by the Customer, the Company shall allow the Customer to make modifications to each such Interconnection Application which increase the system capacity of the Customer's installed Generating Facility by up to 1 kW (100 Watts for Hawaii Electric Light) (when compared to the Customer's original Interconnection Application for such Generating Facility), provided that, in each case, the Customer submits a written request to the Company identifying a reasonable basis for such capacity expansion. For purposes of this Section 7.b, "reasonable basis" may include, without limitation: changes to the Company's qualified equipment list, switching contractors, non-availability of original equipment (and/or availability of better equipment), roof alterations or changes in shading, improved analysis of home electricity use and the evolving equipment requirements of third-party system financing or leasing companies.

c. Any 1 kW increase permitted under this Section 7 shall be measured against the lowest or initial conditional approval system size on record for the Generating Facility, whichever is less.

d. The 1 kW allowance provided pursuant to this Section 7 will not be applied against Commission-approved DER program caps after the applicable DER program capacity limit has been reached. However, the 1 kW allowance provided pursuant to this Section 7 will be applied against Commission-approved DER program caps while the applicable DER program is open and program capacity remains available. For tracking and monitoring purposes, the Company shall maintain a record of all Customers that have, since June 29, 2018, requested, and been approved for, an allowance up to 1 kW under Section 7.b above.

e. With respect to each Interconnection Application submitted by the Customer participating in the Emergency Demand Response Program's Scheduled Dispatch Program, the Company shall allow the Customer to make modifications to each such Interconnection Application which increase the system capacity of the Customer's installed Generating Facility by up to 5 kVA (when compared to the Customer's original Interconnection Application for such Generating Facility), provided that, in each case, the Customer submits the requisite documentation for participation in the Scheduled Dispatch Program.

f. Any 5 kVA increase permitted under this Section 7 for the participation in the Scheduled Dispatch Program shall be measured against the lowest or initial conditional approval system size on record for the Generating Facility, whichever is less.

g. The 5 kVA increase permitted under this Section 7 for the participation in the Scheduled Dispatch Program shall be measured as the post-inverter alternating current power, meaning the sum of the lower of the new generation direct current and the inverter alternating current nominal power ratings per inverter.

h. The 5 kVA allowance provided pursuant to this Section 7 for participation in the Scheduled Dispatch Program will not be applied against Commission-approved DER program caps. The Company will report on generation coming from the Scheduled Dispatch Program and will also provide a breakdown of which underlying DER tariffs the customers are participating in for purposes of the Scheduled Dispatch Program.

Hawaiian Electric

Distributed Energy Resources
EMERGENCY DEMAND RESPONSE (EDRP)
Amendment to Existing Agreement

This Amendment No. ___________ ("Amendment") is entered into by and between Hawaiian Electric Company, Inc. ("Company") and the "Customer-Generator" referenced herein, and amends that certain Distributed Energy Resources Agreement ("Agreement") dated ________________ as stated herein. As hereby amended, the Agreement is hereby ratified and confirmed and shall remain in full force and effect, subject to all of the terms, covenants and conditions therein and herein set forth. This Amendment is effective as of ____________________ .

This Amendment may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument binding all Parties not withstanding that all of the Parties are not signatories to the same counterparts. Signatures may be provided in original ("wet") form or by other means intended to preserve the original graphic and pictorial appearance of the signature, such as a photocopy. A copy of a Party's signature shall be considered an "original" signature for purposes of this Amendment.

Please Include: ☐ **Single Line Diagram** ☐ **Three Line Diagram** (if applicable) ☐ **Site Plan and / or Elevation**

UNDERLYING PROGRAM

☐ NEM	☐ NEM PLUS	☐ CSS	☐ SIA
☐ CGS	☐ CGS PLUS	☐ SMART EXPORT	Agreement ID and Meter Number:

CUSTOMER-GENERATOR

Name:	Email:	
Service Address:	TMK:	
City:	Zip Code:	
Mailing Address:		
City:	State:	Zip Code:
Daytime Phone:		

OWNER-OPERATOR (IF APPLICABLE)

☐ NEW ☐ EXISTING ☐ NOT APPLICABLE

Name:		
Mailing Address:		
City:	State:	Zip Code:
Daytime Phone:		

ELECTRICAL CONTRACTOR INFORMATION

Electrical Company:	Hawaii License #:	
Mailing Address:		
City:	State:	Zip Code:
Daytime Phone:	Email:	

GENERATING SYSTEM CITY & COUNTY PERMIT #: *(To be filled out by the company)*

REASON FOR AMENDMENT/REVISION

Briefly describe the requested changes to the existing amendment:

Hawaiian Electric

Distributed Energy Resources
EMERGENCY DEMAND RESPONSE (EDRP)
Amendment to Existing Agreement

- ❖ I hereby appoint and authorize the contractor listed to act on my behalf in all manners relating to my Distributed Energy Resources (DER) application, including but not limited to, the authority to (i) request, access and receive directly from Hawaiian Electric Company, on my behalf, all information and documentation relating to my proposed project, and (ii) make decisions and execute agreements, if required, regarding the proposed project.
- ❖ This Grant of Authority shall remain in effect until Hawaiian Electric Company receipt of written termination of such Grant of Authority by Customer or resubmittal of an updated Grant of Authority.
- ❖ I acknowledge that this authorization is granted for the sole purpose of my application, and for managing questions related to the system post-installation. Utility service outside of the PV system is not included, unless said information directly affects processing of my application. I understand that a new form must be submitted if I change my installing contractor.
- ❖ I acknowledge that I have had an opportunity to review and seek clarification from Hawaiian Electric and/or my contractor with respect to the EDRP terms and conditions, as such terms are made available by Hawaiian Electric at [Insert appropriate link here], including, but not limited to, the scheduled dispatch of energy storage.
- ❖ I further acknowledge my understanding of the terms and conditions of the EDRP, and c[illegible] participation in the same. I will complete, or have completed, the Scheduled Dispatch Program Agreement, and will abide by the conditions therein.

I certify that, to the best of my knowledge, all the information provided in this Amendment is true and correct. I will not interconnect and operate additions to the existing system without prior written approval by Hawaiian Electric.

Customer Generator:			
	Print	*Signature*	*Date*
Owner-Operator of Generating Facility:			
	Print	*Signature*	*Date*
Company Approval*:	*To be filled out by the company*	*To be filled out by the company*	*To be filled out by the company*
	Print	*Signature*	*Date*

** Subject to the additional terms and conditions set forth in Exhibit A, if any.*

GENERATING FACILITY (MODIFICATIONS TO DER SYSTEM):

Please list all changes from the existing agreement in the sections below. All equipment must comply with the safety and operating standards published in Rule 14H and operate in compliance with the Rules of the corresponding program. Please use + or - to indicate how many items are being added or removed to the existing system in the QTY column. Increases in proposed system capacity may result in additional technical review and approval is subject to program rules.

☐ Not installing new equipment, only enrolling in EDRP.

☐ Committed Capacity __________ kW of existing energy storage discharge capacity for EDRP. (Please describe assigned equipment in the lines below.)

____

____

____

Hawaiian Electric

Distributed Energy Resources
EMERGENCY DEMAND RESPONSE (EDRP)
Amendment to Existing Agreement

GENERATING FACILITY (NEW EQUIPMENT):

Type of Energy Storage Coupling: ☐ AC Coupled ☐ DC Coupled

INVERTERS

Micro inverter	Central/String Inverter	Energy Storage Inverter	Inverter Manufacturer	Inverter Model (Please list exact model #)	QTY	Peak AC Output Rating (kW)*	QTY x Peak AC Output Rating (kW)
☐ 1	☐ 1	☐ 1					
☐ 2	☐ 2	☐ 2					
☐ 3	☐ 3	☐ 3					
** All equipment ratings must match those listed on their manufacturer's specification sheets*					Total Change in Rated Inverter Capacity (kW) =		

PHOTOVOLTAIC MODULES ☐ Not Applicable

	PV Module Manufacturer	PV Module (Please list exact model #)	QTY	STC (kW)	QTY x STC DC Output Rating (kW)
☐ 1					
☐ 2					
☐ 3					
				Total Change in PV Module STC Capacity (kW) =	
				Total Program Size (kW) =	

ENERGY STORAGE ☐ Not Applicable

	Energy Storage Manufacturer	Model (Please list exact model #)	Size kW	Charge/Discharge (kW)	Max Capacity (kWh)	QTY
☐ 1						
☐ 2						
☐ 3						
					Total Rated Capacity (kW) =	
					Total Technical System Size (kW) =	

Will the distribution grid be used to charge the storage device? Yes ☐ No ☐

Type of Operation: ☑ EDRP Scheduled Dispatch of Energy Storage

GENERATOR DISCONNECT Not Applicable

Manufacturer	Catalog #	Type	Rated Amps	Rated Volts

Select all that apply: ☐ Fused ☐ Non-fused ☐ Single Phase ☐ Three Phase ☐ Uses multiple disconnect

Mounting location:

Hawaiian Electric - O'ahu

All Programs Except SIA		Standard Interconnection Agreement (SIA)	
Hawaiian Electric Distributed Energy Resources P.O. Box 2750, CP12-SE Honolulu, HI 96840	Email: connect@HawaiianElectric.com	Hawaiian Electric Attn: SIA; CP10-SN P.O. Box 2750 Honolulu, HI 96840	Email: SIAinfo@HawaiianElectric.com

<u>EXHIBIT 4</u>

Hawaiian Electric Company, Inc.

Proposed Rule No. 31

Appendix A

Scheduled Dispatch Program Agreement

APPENDIX A

SCHEDULED DISPATCH PROGRAM AGREEMENT

This Scheduled Dispatch Program Agreement ("Agreement") is made by and between:

Hawaiian Electric Company, Inc.____________________ ("Company") and

____ ("Customer Battery Storage-Operator")

and is made, effective and binding as of ____________________________ ("Effective Date").

The Company and the Customer Battery Storage-Operator may each be referred to individually as a "Party" and collectively as the "Parties."

WHEREAS, Company is an operating electric public utility subject to the Hawaii Public Utilities Law, Hawaii Revised Statutes, Chapter 269, and the rules and regulations of the Hawaii Public Utilities Commission ("Commission");

WHEREAS, the Customer Battery Storage-Operator receives permanent service from the Company;

WHEREAS, the Customer Battery Storage-Operator qualifies as an "Eligible Customer Battery Storage-Operator," as defined in the Company's Emergency Demand Response Program tariff and its associated Scheduled Dispatch Program Rider ("SDP Tariff");

WHEREAS, Company and Customer Battery Storage-Operator are parties to an underlying interconnection agreement dated ___________ ("Underlying Agreement") under the Company's Net Energy Metering, Customer Self-Supply, Customer Grid-Supply, Customer Grid-Supply Plus, Smart Export, or Standard Interconnection Agreement programs as described in Rule Nos. 18, 22, 23, 24, 25, and Rule 14H Appendix II, respectively;

WHEREAS, the Customer Battery Storage-Operator intends to own and operate a battery storage system charged from the Customer Battery Storage-Operator's solar generating facility pursuant to the requirements of the Scheduled Dispatch Program ("Battery Storage Facility"); and

WHEREAS, this Agreement is contingent upon and supplements the Underlying Agreement which, as may be amended, shall continue in full force and effect notwithstanding the Customer Battery Storage-Operator's participation in the Company's Schedule Dispatch Program pursuant to this Agreement;

NOW, THEREFORE, in consideration of the premises and the respective promises herein, the Company and the Customer Battery Storage-Operator hereby agree as follows:

1. **<u>Notice and Disclaimer Regarding Future Rate and Tariff Modifications.</u>** This Agreement shall, at all times, be subject to modification by the Commission as said Commission may, from time to time, direct in the exercise of its jurisdiction. Without limiting the foregoing, Customer Battery Storage-Operator expressly acknowledges the following:

   - The Emergency Demand Response Program and its associated Scheduled Dispatch Program are subject to modification by the Hawaii Public Utilities Commission ("Commission").

   - **Your Agreement and the Battery Storage Facility shall be subject to any future modifications ordered by the Commission. Such modifications may positively or negatively impact any potential savings in your electricity bill that were calculated by you or presented to you to support your decision to buy or lease a Battery Storage Facility and may otherwise change the value of your Agreement and Battery Storage Facility. You agree to pay for any costs related to such Commission ordered modifications**.

     BY SIGNING BELOW, YOU ACKNOWLEDGE THAT YOU HAVE READ, UNDERSTAND AND AGREE TO THE ABOVE NOTICE AND DISCLAIMER. FURTHER, BY SIGNING BELOW, YOU CONFIRM YOUR UNDERSTANDING THAT ANY POTENTIAL SAVINGS IN YOUR ELECTRICITY BILL THAT WERE CALCULATED BY YOU OR PRESENTED TO YOU TO SUPPORT YOUR DECISION TO BUY OR LEASE A BATTERY STORAGE FACILITY MAY CHANGE.

2. **<u>Effectiveness of Agreement</u>**. This Agreement shall not be effective until approved and executed by each Party, i.e., upon the Effective Date. Customer Battery Storage-Operator shall not operate the Battery Storage Facility prior to approval and execution of this Agreement by the Company, except to the extent allowed for by the Underlying Agreement or to the extent necessary to obtain governmental and utility approvals. Until this Agreement is effective, no Party shall have any legal obligations that extend beyond the Underlying Agreement, arising hereunder, express or implied, and any actions taken by a Party in reliance on the terms of this Agreement prior to the Effective Date shall be at that Party's own risk.

3. **Underlying Interconnection Agreement**. Customer Battery Storage-Operator's Battery Storage Facility enrollment and participation under the Scheduled Dispatch Program is contingent upon current enrollment in the Company's Net Energy Metering, Customer Self-Supply, Customer Grid-Supply, Customer Grid-Supply Plus, Smart Export, or Standard Interconnection Agreement programs as described in Rule Nos. 18, 22, 23, 24, 25, and execution and non-default of the Underlying Agreement. This Agreement shall supplement the Underlying Agreement which, as may be amended, shall continue in full force and effect notwithstanding the Customer Battery Storage-Operator's participation in the Company's Schedule Dispatch Program pursuant to this Agreement.

4. **SDP Tariff.** Unless otherwise provided herein, the terms and conditions governing Customer Battery Storage-Operator's participation in the Scheduled Dispatch Program shall be as set forth in Company's SDP Tariff.

5. **Enrollment and Operation.** Customer Battery Storage-Operator hereby agrees to commit to the following capacity (kW) of maintained discharge from the Battery Storage Facility ("Committed Capacity") on a preset schedule for a daily duration of two hours.

   Customer Battery Storage-Operator's Committed Capacity: _____________kW

   The daily two-hour period during which the Committed Capacity will be dispatched ("Dispatch Period") will be specified by the Company at the time of enrollment and may be revised by the Company with reasonable notice.

   a) Within 30 days of commencement of discharge of Committed Capacity, Customer Battery Storage-Operator must provide 14 consecutive days of operational performance data in five (5) minute intervals as necessary to verify the operation of the Battery Storage Facility in accordance with this Agreement. The Company shall complete such verification within 10 business days of the receipt of such performance data from Customer Battery Storage-Operator.
   b) If no requests for additional data or concerns are expressed regarding operation of the Battery Storage Facility as specified in this Agreement are communicated (in written or digital form) to the Customer Battery Storage-Operator by Company, the Customer Battery Storage-Operator will be deemed verified as operating in compliance with this Agreement.
   c) Notwithstanding any other provision specified in the underlying program tariff in which the Customer Battery Storage-Operator participates or in the interconnection agreement to which the Customer Battery Storage-Operator is a party, as applicable, energy exported to the grid from the Battery Storage Facility during the Dispatch Period shall be permitted and, if applicable, compensated in accordance with the Customer Battery Storage-Operator's underlying program tariff.

d) Energy discharged during the Dispatch Period from the Battery Storage Facility may either serve onsite load or be exported to the grid. Customer Battery Storage-Operator enrolled in Scheduled Dispatch is required to manage their DER systems to automatically prioritize battery charging during periods of substantial solar panel insolation in order to most reliably serve the two-hour battery discharge commitment as scheduled by the Company.
e) Customer Battery Storage-Operator shall use the default ramp rate of equipment for the Committed Capacity during the Dispatch Period. Deviations from the default ramp rate may be required in certain circumstances where the default ramp rate may pose adverse impacts to grid power quality. The Company will notify the Customer Battery Storage-Operator of any such deviation when the Dispatch Period is specified or revised.

6. **Term and Termination.** This Agreement shall continue for ten (10) years from the commencement of the discharge of Committed Capacity for the Dispatch Period in accordance with this Agreement. Customer Battery Storage-Operator may terminate this Agreement at any time with sixty (60) days written notice. If termination occurs prior to completion of its ten-year commitment, Customer Battery Storage-Operator shall return a prorated portion of the compensation received pursuant to the SDR Tariff. The prorated portion of the compensation shall be based on the remaining portion of the ten-year commitment, calculated from the date of termination as a fraction of the Customer Battery Storage-Operator's ten-year commitment. Customer Battery Storage-Operator may either pay such owed amount in full or make other arrangements with the Company prior to termination. The Company will not charge interest on a payment if final payment is made within one year of date of termination. Company may terminate this Agreement at any time if Customer Battery-Storage Operator fails to comply with any term of this Agreement, the Underlying Agreement, or if the Customer Battery-Storage Operator fails to be an Eligible Customer Battery-Storage Operator.

7. **Failure to Perform.** If the Company identifies concerns or issues relating to the Battery Storage Facility's performance, including, without limitation, potential non-compliance with this Rule pertaining to the discharge of Committed Capacity for the Discharge Period, the Company may conduct a performance audit to monitor and document conditions.

a) The Company shall provide the Customer Battery Storage-Operator written or digital notice at least seven (7) days in advance of any performance audit.
b) Customer Battery Storage-Operator shall be required to provide five (5) minute interval data as necessary to verify operation of the Battery Storage Facility in accordance with this Agreement with five (5) business days of request from Company.

c) If the Battery Storage Facility fails to perform in compliance with this Rule, the Company will provide to the Customer Battery Storage-Operator a written notice of Failure to Perform, which will include documentation explaining the non-compliance of operation.
d) Customer Battery Storage-Operator will have 30 days from the date of such notice of Failure to Perform to cure the non-compliance.
e) If the non-compliance persists beyond the 30-day cure period, Customer Battery Storage-Operator may be charged up to $100 monthly until either the non-compliance is rectified or the Company has recovered the full prorated compensation paid to Customer Battery Storage-Operator pursuant to the SDR Tariff.

8. **<u>Scope of Agreement.</u>** The Parties understand and agree that this Agreement is contingent upon the Underlying Agreement and applies only to the operation of Customer Battery Storage-Operator's Battery Storage Facility as specified by the Scheduled Dispatch Program.

9. **<u>Metering</u>**. Within fifteen (15) days of execution of this Agreement, the Company will supply, own, and maintain all necessary meters and associated equipment utilized for billing and energy purchase. The meters will be tested and read in accordance with the rules of the Commission and the Company. The Customer Battery Storage-Operator at its expense, shall provide, install and maintain all conductors, service switches, fuses, meter sockets, meter instrument transformer housing and mountings, switchboard meter test buses, meter panels and similar devices required for service connection and meter installations on the Customer Battery Storage-Operator's premises in accordance with the Company's Rule 14H.

10. **<u>Compensation.</u>** The terms regarding compensation to the Customer Battery System-Operator for its participation in the Company's Scheduled Dispatch Program shall be as set forth in the SDR Tariff.

11. **<u>Data and Private Information.</u>** Company access to personal data, including information for tax reporting purposes, data related to the Battery Storage Facility performance and usage, electrical utility account information, usage history, and meter data is required for enrollment under the Company's Scheduled Dispatch Program. All data access, use, and sharing is subject to the terms of Hawaiian Electric's Customer Information Privacy Policy (available at https://www.hawaiianelectric.com/privacy-notice/customer-information-privacy-policy) and applicable law.

    a) **By executing this Agreement, Customer Battery Storage-Operator approves and consents to provide data required for enrollment under Scheduled Dispatch Program.**
    b) **Tax Identification Number ("TIN") must be provided to Company via secure transfer prior to the Company executing this Agreement.**

12. **Indemnification.**

a) The Customer Battery Storage-Operator shall indemnify, defend and hold harmless the Company and its officers, directors, agents and employees, from and against all liabilities, damages, losses, fines, penalties, claims, demands, suits, costs and expenses (including reasonable attorney's fees and expenses) to or by third persons, including the Company's employees or subcontractors, for injury or death, or for injury to property, arising out of the actions or inactions of the Customer Battery Storage-Operator (or those of anyone under its control or on its behalf) with respect to its obligations under this Agreement, and/or arising out of the installation, operation and maintenance of the Battery Storage Facility, except to the extent that such injury, death or damage is attributable to the gross negligence or intentional act or omission of the Company or its officers, directors, agents or employees.

Provided, however, where the Customer Battery Storage-Operator is an agency of the United States, the following Section shall be applicable in place of Paragraph 12(a):

"The United States understands that it may be held liable for loss, damages expense and liability to third persons and injury to or death of persons or injury to property caused by the United States in its engineering design, construction ownership or operations of, or the making of replacements, additions betterment to, or by failure of, any of such party's works or facilities used in connection with this Agreement to the extent allowed by the Federal Tort Claims Act 28 U.S.C. § 2671 et seq. and the Agreement Disputes Act of 1978, 41 U.S.C. §§ 601-613.

Company shall be responsible for damages or injury caused by Company, Company's agents, officers, and employees in the course of their employment to the extent permitted by law."

Provided, however, where the Customer Battery Storage-Operator is an agency of the State of Hawaii (the "State"), the following Section shall be applicable in place of Paragraph 12(a):

"The State shall be responsible for damages or injury caused by the State's agents, officers, and employees in the course of their employment to the extent that the State's liability for such damage or injury has been determined by a court or otherwise agreed to by the State. The State shall pay for such damage and injury to the extent permitted by law. The State shall use reasonable good faith efforts to pursue any approvals from the Legislature and the Governor that may be required to obtain the funding necessary to enable the State to perform its obligations or cover its liabilities hereunder. The State shall not request Company to indemnify the State for, or hold the State harmless from, any claims for such damages or injury.

Company shall be responsible for damages or injury caused by Company, Company's agents, officers, and employees in the course of their employment to the extent that Company's liability for such damage or injury has been determined by a court or otherwise agreed to by Company, and Company shall pay for such damage and injury to the extent permitted by law. Company shall not request the State to indemnify Company for, or hold Company harmless from, any claims for such damages or injury."

b) The Company shall indemnify, defend and hold harmless the Customer Battery Storage-Operator, and its officers, directors, agents and employees, from and against all liabilities, damages, losses, fines, penalties, claims, demands, suits, costs and expenses (including reasonable attorney's fees and expenses) to or by third persons, including the Customer Battery Storage-Operator's employees or subcontractors, for injury or death, or for injury to property, arising out of the actions or inactions of the Company (or those of anyone under its control or on its behalf) with respect to its obligations under this Agreement, except to the extent that such injury, death or damage is attributable to the gross negligence or intentional act or omission of the Customer Battery Storage-Operator or its officers, directors, agents or employees.

c) Nothing in this Agreement shall create any duty to, any standard of care with reference to, or any liability to any person not a party to it.

13. **Limitation of Liability**. Neither by inspection, if any, or non-rejection, nor in any other way, does the Company give any warranty, express or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, installed or maintained by the Customer Battery Storage-Operator, including without limitation the Battery Storage Facility and any structures, equipment, wires, appliances or devices appurtenant thereto.

14. **Force Majeure**. For purposes of this Agreement, "Force Majeure Event" means any event: (a) that is beyond the reasonable control of the affected Party; and (b) that the affected Party is unable to prevent or provide against by exercising reasonable diligence, including the following events or circumstances, but only to the extent they satisfy the preceding requirements: (a) acts of war, public disorder, insurrection or rebellion; floods, hurricanes, earthquakes, lighting, storms, and other natural calamities; explosions or fires; strikes, work stoppages, or labor disputes; embargoes; and sabotage. If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, such Party will promptly notify the other Parties in writing and will keep the other Parties informed on a continuing basis of the scope and duration of the Force Majeure Event. The affected Party will specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the affected Party is taking to mitigate the effects of the event on its performance. The affected Party will be entitled to suspend or modify its performance of obligations under this Agreement, other than the obligation to make payments then due or becoming due under this Agreement, but only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of reasonable efforts. The affected Party will use reasonable efforts to resume its performance as soon as possible.

15. **Additional Information**. By signing this Agreement, the Customer Battery Storage-Operator expressly agrees and authorizes Company to (1) request and obtain additional information from Customer Battery Storage-Operator relating to the Battery Storage Facility, and/or (2) make modifications to the Customer Battery Storage-Operator's Battery Storage Facility, at no cost to the Company, where reasonably necessary, to serve the Customer Battery Storage-Operator under this Agreement or to ensure reliability, safety of operation, and power quality of the Company's system.

16. **Notices**. Any notice required under this Agreement shall be in writing and mailed at any United States Post Office with postage prepaid and addressed to the Party, or personally delivered to the Party at the address identified on the last page of the Agreement. Changes in such designation may be made by notice similarly given. Notice sent by mail shall be deemed to have been given on the date of actual delivery or at the expiration of the fifth day after the date of mailing, whichever is earlier.

17. **Miscellaneous.**

a) **Governing Law and Regulatory Authority.** This Agreement was executed in the State of Hawaii and must in all respects be interpreted, governed, and construed under the laws of the State of Hawaii. This Agreement is subject to, and the Parties' obligations hereunder include, operating in full compliance with all valid, applicable federal, state, and local laws or ordinances, and all applicable rules, regulations, orders of, and tariffs approved by, duly constituted regulatory authorities having jurisdiction.

b) **Amendment, Modifications, or Waiver**. This Agreement may not be altered or modified by any of the Parties, except by an instrument in writing executed by each of them. None of the provisions of this Agreement shall be considered waived by a Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect. This Agreement contains the entire agreement and understanding between the Parties, their agents, and employees as to the subject matter of this Agreement. Each Party also represents that in entering into this Agreement, it has not relied on any promise, inducement, representation, warranty, agreement or other statement not set forth in this Agreement.

c) **Assignment.** This Agreement may not be assigned by any Party without the prior written consent of the other Parties. Such consent shall not be unreasonably withheld.

d) **Binding Effect.** This Agreement shall be binding upon and inure to the benefit of the Parties hereto and their respective successors, legal representatives, and permitted assigns.

e) **Relationship of Parties**. Nothing in this Agreement shall be deemed to constitute any Party hereto as partner, agent or representative of the other Parties or to create any fiduciary relationship between the Parties.

f) **Limitations**. Nothing in this Agreement shall limit the Company's ability to exercise its rights or expand or diminish its liability with respect to the provision of electrical service pursuant to the Company's tariffs as filed with the Commission, or the Commission's Standards for Electric Utility Service in the State of Hawaii, which currently are included in the Commission's General Order Number 7, as either may be amended from time to time.

g) **<u>Execution of Agreement; Multiple Counterparts</u>**. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument binding all Parties notwithstanding that all of the Parties are not signatories to the same counterparts. Signatures may be provided in original ("wet") form or by other means intended to preserve the original graphic and pictorial appearance of the signature, such as a photocopy. A copy of a Party's signature shall be considered an "original" signature for purposes of this Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused two originals of this Agreement to be executed by their duly authorized representatives. This Agreement is effective as of the date first set forth above.

CUSTOMER BATTERY STORAGE-OPERATOR

By: ______________________________ ______________
Signature Date

Name (Print): ______________________________

Company Name
(if applicable): ______________________________

Title (if applicable): ______________________________

HAWAIIAN ELECTRIC COMPANY

By: ______To be completed by Company____________ ____ To be completed by Company ___
Signature Date

Name (Print): ____________ To be completed by Company ____________

Title (if applicable): ____________ To be completed by Company ____________

MAILING ADDRESS

Hawaiian Electric Company
Distributed Energy Resources Division
P.O. Box 2750 (CP12-SE)
Honolulu, HI 96840
HAWAIIAN ELECTRIC COMPANY, INC.
Order No.

Illustrative Purposes Only

Emergency Demand Response Customer Incentives

Cost Recovery Summary

Residential	**2021**	**2022**	**2023**	**2024**
Preliminary Incentive Receivable	$ 95,625	$ 1,456,875	$ 2,778,750	$ 3,060,000
Preliminary Carrying Charges	$ 85,528	$ 1,258,520	$ 2,256,431	$ 2,246,872
Total Cost Recovery	$ 181,153	$ 2,715,395	$ 5,035,181	$ 5,306,872
Commercial				
Preliminary Incentive Receivable	$ 10,625	$ 161,875	$ 308,750	$ 340,000
Preliminary Carrying Charges	$ 9,503	$ 139,836	$ 250,715	$ 249,652
Total Cost Recovery	$ 20,128	$ 301,711	$ 559,465	$ 589,652
Residential + Commercial				
Preliminary Incentive Receivable	$ 106,250	$ 1,618,750	$ 3,087,500	$ 3,400,000
Preliminary Carrying Charges	$ 95,031	$ 1,398,355	$ 2,507,145	$ 2,496,524
Total Cost Recovery	$ 201,281	$ 3,017,105	$ 5,594,645	$ 5,896,524

Assumptions:

Quarterly incentives will be paid out to both residential and commercial customers on the last day of the quarter & and r

Recovery of the carrying costs are to be recovered within the same quarter as incurred, therefore no compounding of the

Quarterly incentives totaling $34,000,000 will be paid out to customers in 2021-2023.

The quarterly incentives recovery period is 10 years (40 quarters).

Carrying Cost Rates:	**Annual**	**Quarterly**
Pre-acceptance (Short-term rate)	1.75%	0.44%
AFUDC Debt Rate	5.49%	0.46%
AFUDC Equity Rate	15.84%	1.32%

Income Tax Gross-up factor of AFUDC equity is 1.3468354

The pre-acceptance (ST rate) rate will be compounded on a quarterly basis to the outstanding incentive receivable balance up until DSM recovery begins. However, since the quarterly incentives are paid out on the last day of the quarter and the recovery period begins the following quarter (the next day), no pre-acceptance (ST rate) is computed.

After the DSM recovery begins, the AFUDC rates will be applied quarterly to the outstanding incentive ending balance of

The recovery outlook for this illustration is for 2021-2024

Illustrative Purposes Only
Emergency Demand Response Incentives
Cost Recovery Schedule

EDR Incentive Cost (Does not split Res & Com)

Timeline	H2 2021	2022	2023	2024	2025	2026
Annual Enrolled Resources (kW)	**10,000**	**30,000**	**10,000**	**0**	**0**	**0**
Tier 1 Incentive Cost ($)	8,500,000	4,250,000	0	0	0	0
Tier 2 Incentive Cost ($)	0	11,250,000	0	0	0	0
Tier 3 Incentive Cost ($)	0	5,000,000	5,000,000	0	0	0
Total Annual Incentive Cost ($)	**8,500,000**	**20,500,000**	**5,000,000**	**0**	**0**	**0**

Residential Costs

Timeline	H2 2021	2022	2023	2024	2025	2026
Annual Enrolled Resources (kW)	**9,000**	**27,000**	**9,000**	**0**	**0**	**0**
Tier 1 Incentive Cost ($)	7,650,000	3,825,000	0	0	0	0
Tier 2 Incentive Cost ($)	0	10,125,000	0	0	0	0
Tier 3 Incentive Cost ($)	0	4,500,000	4,500,000	0	0	0
Total Annual Incentive Cost ($)	**7,650,000**	**18,450,000**	**4,500,000**	**0**	**0**	**0**

Commercial Costs

Timelie	H2 2021	2022	2023	2024	2025	2026
Annual Enrolled Resources (kW)	**1,000**	**3,000**	**1,000**	**0**	**0**	**0**
Tier 1 Incentive Cost ($)	850,000	425,000	0	0	0	0
Tier 2 Incentive Cost ($)	0	1,125,000	0	0	0	0
Tier 3 Incentive Cost ($)	0	500,000	500,000	0	0	0
Total Annual Incentive ($)	**850,000**	**2,050,000**	**500,000**	**0**	**0**	**0**

Illustrative Purposes Only
Emergency Demand Response Incentives
Cost Recovery Schedule

Residential Recovery Schedule

Timeline	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022
Quarterly Cost Expenditure ($):	**3,825,000**	**3,825,000**	**4,612,500**	**4,612,500**	**4,612,500**	**4,612,500**
Recovery for Q3 2021 Costs ($)		95,625	95,625	95,625	95,625	95,625
Recovery for Q4 2021 Costs ($)			95,625	95,625	95,625	95,625
Recovery for Q1 2022 Costs ($)				115,313	115,313	115,313
Recovery for Q2 2022 Costs ($)					115,313	115,313
Recovery for Q3 2022 Costs ($)						115,313
Recovery for Q4 2022 Costs ($)						
Recovery for Q1 2023 Costs ($)						
Recovery for Q2 2023 Costs ($)						
Recovery for Q3 2023 Costs ($)						
Recovery for Q4 2023 Costs ($)						
Recovery Total ($):		**95,625**	**191,250**	**306,563**	**421,875**	**537,188**
Carrying Cost for Q3 2021 Costs ($)		85,528	83,390	81,252	79,113	76,975
Carrying Cost for Q4 2021 Costs ($)			85,528	83,390	81,252	79,113
Carrying Cost for Q1 2022 Costs ($)				103,137	100,558	97,980
Carrying Cost for Q2 2022 Costs ($)					103,137	100,558
Carrying Cost for Q3 2022 Costs ($)						103,137
Carrying Cost for Q4 2022 Costs ($)						
Carrying Cost for Q1 2023 Costs ($)						
Carrying Cost for Q2 2023 Costs ($)						
Carrying Cost for Q3 2023 Costs ($)						
Carrying Cost for Q4 2023 Costs ($)						
Carrying Cost Total ($)		**85,528**	**168,918**	**267,778**	**364,060**	**457,764**
Recovery + Carrying Cost Total ($)		**181,153**	**360,168**	**574,341**	**785,935**	**994,951**

Illustrative Purposes Only
Emergency Demand Response Incentives
Cost Recovery Schedule

Commercial Recovery Schedule

Timeline	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022
Quarterly Cost Expenditure ($):	**425,000**	**425,000**	**512,500**	**512,500**	**512,500**	**512,500**
Recovery for Q3 2021 Costs ($)		10,625	10,625	10,625	10,625	10,625
Recovery for Q4 2021 Costs ($)			10,625	10,625	10,625	10,625
Recovery for Q1 2022 Costs ($)				12,813	12,813	12,813
Recovery for Q2 2022 Costs ($)					12,813	12,813
Recovery for Q3 2022 Costs ($)						12,813
Recovery for Q4 2022 Costs ($)						
Recovery for Q1 2023 Costs ($)						
Recovery for Q2 2023 Costs ($)						
Recovery for Q3 2023 Costs ($)						
Recovery for Q4 2023 Costs ($)						
Recovery Total ($):		**10,625**	**21,250**	**34,063**	**46,875**	**59,688**
Carrying Cost for Q3 2021 Costs ($)		9,503	9,266	9,028	8,790	8,553
Carrying Cost for Q4 2021 Costs ($)			9,503	9,266	9,028	8,790
Carrying Cost for Q1 2022 Costs ($)				11,460	11,173	10,887
Carrying Cost for Q2 2022 Costs ($)					11,460	11,173
Carrying Cost for Q3 2022 Costs ($)						11,460
Carrying Cost for Q4 2022 Costs ($)						
Carrying Cost for Q1 2023 Costs ($)						
Carrying Cost for Q2 2023 Costs ($)						
Carrying Cost for Q3 2023 Costs ($)						
Carrying Cost for Q4 2023 Costs ($)						
Carrying Cost Total ($)		**9,503**	**18,769**	**29,753**	**40,451**	**50,863**
Recovery + Carrying Cost Total ($)		**20,128**	**40,019**	**63,816**	**87,326**	**110,550**

Illustrative Purposes Only
Emergency Demand Response Incentives
Cost Recovery Schedule

<u>EDR Incentive Cost</u> (Does not split Res & Com)

Timeline	2027	2028	2029	2032	2032	2032	H1 2033
Annual Enrolled Resources (kW)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Tier 1 Incentive Cost ($)	0	0	0	0	0	0	0
Tier 2 Incentive Cost ($)	0	0	0	0	0	0	0
Tier 3 Incentive Cost ($)	0	0	0	0	0	0	0
Total Annual Incentive Cost ($)	**0**	**0**	**0**	**0**	**0**	**0**	**0**

<u>Residential Costs</u>

Timeline	2027	2028	2029	2032	2032	2032	H1 2033
Annual Enrolled Resources (kW)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Tier 1 Incentive Cost ($)	0	0	0	0	0	0	0
Tier 2 Incentive Cost ($)	0	0	0	0	0	0	0
Tier 3 Incentive Cost ($)	0	0	0	0	0	0	0
Total Annual Incentive Cost ($)	**0**	**0**	**0**	**0**	**0**	**0**	**0**

<u>Commercial Costs</u>

Timelie	2027	2028	2029	2032	2032	2032	H1 2033
Annual Enrolled Resources (kW)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Tier 1 Incentive Cost ($)	0	0	0	0	0	0	0
Tier 2 Incentive Cost ($)	0	0	0	0	0	0	0
Tier 3 Incentive Cost ($)	0	0	0	0	0	0	0
Total Annual Incentive ($)	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Illustrative Purposes Only
Emergency Demand Response Incentives
Cost Recovery Schedule

Residential Recovery Schedule

Timeline	Q1 2023	Q2 2023	Q3 2023	Q4 2023	Q1 2024	Q2 2024	Q3 2024	Q4 2024
Quarterly Cost Expenditure ($):	**1,125,000**	**1,125,000**	**1,125,000**	**1,125,000**				
Recovery for Q3 2021 Costs ($)	95,625	95,625	95,625	95,625	95,625	95,625	95,625	95,625
Recovery for Q4 2021 Costs ($)	95,625	95,625	95,625	95,625	95,625	95,625	95,625	95,625
Recovery for Q1 2022 Costs ($)	115,313	115,313	115,313	115,313	115,313	115,313	115,313	115,313
Recovery for Q2 2022 Costs ($)	115,313	115,313	115,313	115,313	115,313	115,313	115,313	115,313
Recovery for Q3 2022 Costs ($)	115,313	115,313	115,313	115,313	115,313	115,313	115,313	115,313
Recovery for Q4 2022 Costs ($)	115,313	115,313	115,313	115,313	115,313	115,313	115,313	115,313
Recovery for Q1 2023 Costs ($)		28,125	28,125	28,125	28,125	28,125	28,125	28,125
Recovery for Q2 2023 Costs ($)			28,125	28,125	28,125	28,125	28,125	28,125
Recovery for Q3 2023 Costs ($)				28,125	28,125	28,125	28,125	28,125
Recovery for Q4 2023 Costs ($)					28,125	28,125	28,125	28,125
Recovery Total ($):	**652,500**	**680,625**	**708,750**	**736,875**	**765,000**	**765,000**	**765,000**	**765,000**
Carrying Cost for Q3 2021 Costs ($)	74,837	72,699	70,561	68,422	66,284	64,146	62,008	59,870
Carrying Cost for Q4 2021 Costs ($)	76,975	74,837	72,699	70,561	68,422	66,284	64,146	62,008
Carrying Cost for Q1 2022 Costs ($)	95,401	92,823	90,245	87,666	85,088	82,509	79,931	77,353
Carrying Cost for Q2 2022 Costs ($)	97,980	95,401	92,823	90,245	87,666	85,088	82,509	79,931
Carrying Cost for Q3 2022 Costs ($)	100,558	97,980	95,401	92,823	90,245	87,666	85,088	82,509
Carrying Cost for Q4 2022 Costs ($)	103,137	100,558	97,980	95,401	92,823	90,245	87,666	85,088
Carrying Cost for Q1 2023 Costs ($)		25,155	24,526	23,898	23,269	22,640	22,011	21,382
Carrying Cost for Q2 2023 Costs ($)			25,155	24,526	23,898	23,269	22,640	22,011
Carrying Cost for Q3 2023 Costs ($)				25,155	24,526	23,898	23,269	22,640
Carrying Cost for Q4 2023 Costs ($)					25,155	24,526	23,898	23,269
Carrying Cost Total ($)	**548,889**	**559,454**	**569,390**	**578,698**	**587,376**	**570,271**	**553,165**	**536,059**
Recovery + Carrying Cost Total ($)	**1,201,389**	**1,240,079**	**1,278,140**	**1,315,573**	**1,352,376**	**1,335,271**	**1,318,165**	**1,301,059**

Illustrative Purposes Only
Emergency Demand Response Incentives
Cost Recovery Schedule

Commercial Recovery Schedule

Timeline	Q1 2023	Q2 2023	Q3 2023	Q4 2023	Q1 2024	Q2 2024	Q3 2024	Q4 2024
Quarterly Cost Expenditure ($):	**125,000**	**125,000**	**125,000**	**125,000**				
Recovery for Q3 2021 Costs ($)	10,625	10,625	10,625	10,625	10,625	10,625	10,625	10,625
Recovery for Q4 2021 Costs ($)	10,625	10,625	10,625	10,625	10,625	10,625	10,625	10,625
Recovery for Q1 2022 Costs ($)	12,813	12,813	12,813	12,813	12,813	12,813	12,813	12,813
Recovery for Q2 2022 Costs ($)	12,813	12,813	12,813	12,813	12,813	12,813	12,813	12,813
Recovery for Q3 2022 Costs ($)	12,813	12,813	12,813	12,813	12,813	12,813	12,813	12,813
Recovery for Q4 2022 Costs ($)	12,813	12,813	12,813	12,813	12,813	12,813	12,813	12,813
Recovery for Q1 2023 Costs ($)		3,125	3,125	3,125	3,125	3,125	3,125	3,125
Recovery for Q2 2023 Costs ($)			3,125	3,125	3,125	3,125	3,125	3,125
Recovery for Q3 2023 Costs ($)				3,125	3,125	3,125	3,125	3,125
Recovery for Q4 2023 Costs ($)					3,125	3,125	3,125	3,125
Recovery Total ($):	**72,500**	**75,625**	**78,750**	**81,875**	**85,000**	**85,000**	**85,000**	**85,000**
Carrying Cost for Q3 2021 Costs ($)	8,315	8,078	7,840	7,602	7,365	7,127	6,890	6,652
Carrying Cost for Q4 2021 Costs ($)	8,553	8,315	8,078	7,840	7,602	7,365	7,127	6,890
Carrying Cost for Q1 2022 Costs ($)	10,600	10,314	10,027	9,741	9,454	9,168	8,881	8,595
Carrying Cost for Q2 2022 Costs ($)	10,887	10,600	10,314	10,027	9,741	9,454	9,168	8,881
Carrying Cost for Q3 2022 Costs ($)	11,173	10,887	10,600	10,314	10,027	9,741	9,454	9,168
Carrying Cost for Q4 2022 Costs ($)	11,460	11,173	10,887	10,600	10,314	10,027	9,741	9,454
Carrying Cost for Q1 2023 Costs ($)		2,795	2,725	2,655	2,585	2,516	2,446	2,376
Carrying Cost for Q2 2023 Costs ($)			2,795	2,725	2,655	2,585	2,516	2,446
Carrying Cost for Q3 2023 Costs ($)				2,795	2,725	2,655	2,585	2,516
Carrying Cost for Q4 2023 Costs ($)					2,795	2,725	2,655	2,585
Carrying Cost Total ($)	**60,988**	**62,162**	**63,266**	**64,300**	**65,264**	**63,363**	**61,463**	**59,562**
Recovery + Carrying Cost Total ($)	**133,488**	**137,787**	**142,016**	**146,175**	**150,264**	**148,363**	**146,463**	**144,562**

Illustrative Purposes Only

Emergency Demand Response Incentives

2021-2024 Rate and Bill Impact for EDR

		2021	2022			
		Q4	Q1	Q2	Q3	Q4
Residential						
a	Total Cost Recovery, $	$181,153	$360,168	$574,341	$785,935	$994,951
b	Revenue Tax Adjustment	1.0975	1.0975	1.0975	1.0975	1.0975
c	Revenue Requirement, $	$198,818	$395,289	$630,347	$862,575	$1,091,973
d	Residential Sales, GWh	417.0	380.6	375.6	454.7	422.8
e	Impact on DSM Surcharge, cents/kWh	0.0477	0.1039	0.1678	0.1897	0.2583
f	Typical Residential Use per Month, kWh	500	500	500	500	500
g	Typical Residential Bill Impact, $/Month	0.24	0.52	0.84	0.95	1.29
Commercial						
h	Total Cost Recovery, $	$20,128	$40,019	$63,816	$87,326	$110,550
i	Revenue Tax Adjustment	1.0975	1.0975	1.0975	1.0975	1.0975
j	Revenue Requirement, $	$22,091	$43,921	$70,039	$95,842	$121,330
k	Commercial Sales, GWh	1147.8	1085.4	1081.1	1299.6	1202.3
l	Impact on DSM Surcharge, cents/kWh	0.0019	0.0040	0.0065	0.0074	0.0101

Illustrative Purposes Only

Emergency Demand Response Incentives

2021-2024 Rate and Bill Impact for EDR

		2023			
		Q1	Q2	Q3	Q4
Residential					
a	Total Cost Recovery, $	$1,201,389	$1,240,079	$1,278,140	$1,315,573
b	Revenue Tax Adjustment	1.0975	1.0975	1.0975	1.0975
c	Revenue Requirement, $	$1,318,541	$1,361,004	$1,402,777	$1,443,860
d	Residential Sales, GWh	378.0	372.9	453.9	422.5
e	Impact on DSM Surcharge, cents/kWh	0.3489	0.3650	0.3091	0.3417
f	Typical Residential Use per Month, kWh	500	500	500	500
g	Typical Residential Bill Impact, $/Month	1.74	1.82	1.55	1.71
Commercial					
h	Total Cost Recovery, $	$133,488	$137,787	$142,016	$146,175
i	Revenue Tax Adjustment	1.0975	1.0975	1.0975	1.0975
j	Revenue Requirement, $	$146,505	$151,223	$155,864	$160,429
k	Commercial Sales, GWh	1084.4	1089.1	1317.1	1221.8
l	Impact on DSM Surcharge, cents/kWh	0.0135	0.0139	0.0118	0.0131

Illustrative Purposes Only

Emergency Demand Response Incentives

2021-2024 Rate and Bill Impact for EDR

		2024			
		Q1	Q2	Q3	Q4
Residential					
a	Total Cost Recovery, $	$1,352,376	$1,335,271	$1,318,165	$1,301,059
b	Revenue Tax Adjustment	1.0975	1.0975	1.0975	1.0975
c	Revenue Requirement, $	$1,484,252	$1,465,478	$1,446,705	$1,427,931
d	Residential Sales, GWh	382.4	371.8	453.7	422.7
e	Impact on DSM Surcharge, cents/kWh	0.3881	0.3941	0.3188	0.3378
f	Typical Residential Use per Month, kWh	500	500	500	500
g	Typical Residential Bill Impact, $/Month	1.94	1.97	1.59	1.69
Commercial					
h	Total Cost Recovery, $	$150,264	$148,363	$146,463	$144,562
i	Revenue Tax Adjustment	1.0975	1.0975	1.0975	1.0975
j	Revenue Requirement, $	$164,917	$162,831	$160,745	$158,659
k	Commercial Sales, GWh	1113.6	1097.5	1334.9	1238.1
l	Impact on DSM Surcharge, cents/kWh	0.0148	0.0148	0.0120	0.0128

Illustrative Purposes Only
Q3 2021 Emergncy Demand Response Incentive Receivable - Residential

Beginning Balance as of 9/30/2021	**3,825,000**					
Incentive Receivable Recovery Period (Q4 2021 - Q3 2031)	40 quarters					
Line No.	**A**	**B**	**C**		**D**	**E**
	Pre-acceptance (ST rate)	AFUDC Debt rate	AFUDC Equity rate		Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1 Carrying cost rate (annual)	**1.75%**	**1.83% B1**		**5.28% C1**	**7.11%**	**1.3468354**
2 Carrying cost rate (Quarterly)	**0.4375%**	**0.46% B2**		**1.32% C2**	**1.78%**	

Line No.		F	G		H	I		J	K	L	M
		Deferred Incentive			**Carrying Costs**						
		Amort of Incentive Receivable	**Incentive Receivable Balance**		**ADIT**	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	3,825,000		-	3,825,000	-	-	-	-	-
4	Q4 2021	(95,625)	3,729,375		-	3,729,375	-	17,511	50,501	68,017	85,528
	Total 2021 Amort. of Incentive Receivable Balance	**(95,625)**		**Total Accrued 2021 Carrying Costs**			**-**	**17,511**	**50,501**	**68,017**	**85,528**
5	Q1 2022	(95,625)	3,633,750		-	3,633,750	-	17,073	49,239	66,317	83,390
6	Q2 2022	(95,625)	3,538,125		-	3,538,125	-	16,635	47,976	64,616	81,252
7	Q3 2022	(95,625)	3,442,500		-	3,442,500	-	16,198	46,714	62,916	79,113
8	Q4 2022	(95,625)	3,346,875		-	3,346,875	-	15,760	45,451	61,215	76,975
9	**Total 2022 Amort. of Incentive Receivable Balance**	**(382,500)**		**Total Accrued 2022 Carrying Costs**			**-**	**65,666**	**189,381**	**255,064**	**320,730**
10	Q1 2023	(95,625)	3,251,250		-	3,251,250	-	15,322	44,189	59,515	74,837
11	Q2 2023	(95,625)	3,155,625		-	3,155,625	-	14,884	42,926	57,815	72,699
12	Q3 2023	(95,625)	3,060,000		-	3,060,000	-	14,446	41,664	56,114	70,561
13	Q4 2023	(95,625)	2,964,375		-	2,964,375	-	14,009	40,401	54,414	68,422
	Total 2023 Amort. of Incentive Receivable Balance	**(382,500)**		**Total Accrued 2023 Carrying Costs**			**-**	**58,661**	**169,180**	**227,858**	**286,519**
14	Q1 2024	(95,625)	2,868,750		-	2,868,750	-	13,571	39,139	52,713	66,284
15	Q2 2024	(95,625)	2,773,125		-	2,773,125	-	13,133	37,876	51,013	64,146
16	Q3 2024	(95,625)	2,677,500		-	2,677,500	-	12,695	36,614	49,312	62,008
17	Q4 2024	(95,625)	2,581,875		-	2,581,875	-	12,258	35,351	47,612	59,870
	Total 2024 Amort. of Incentive Receivable Balance	**(382,500)**		**Total Accrued 2024 Carrying Costs**			**-**	**51,657**	**148,979**	**200,651**	**252,308**

Informational Purposes Only
Q4 2021 Emergency Demand Response Incentive Receivable - Residential

Beginning Balance as of 12/31/2021	**3,825,000**	
Incentive Receivable Recovery Period (Jan 2022 - Dec 2031)	40 quarters	

Line No.		**A**	**B**	**C**	**D**	**E**
		Pre-acceptance (ST rate)	AFUDC Debt rate	AFUDC Equity rate	Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1	Carrying cost rate (annual)	**1.75%**	**1.83% B1**	**5.28% C1**	**7.11%**	**1.3468354**
2	Carrying cost rate (Quarterly)	**0.4375%**	**0.46% B2**	**1.32% C2**	**1.78%**	

Line No.		**F**	**G**	**H**	**I**		**J**	**K**	**L**	**M**
		Deferred Incentive		**Carrying Costs**						
		Amort of Incentive Receivable	**Incentive Receivable Balance**	**ADIT**	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	-	-	-	-	-	-	-	-
4	Q4 2021	-	3,825,000	-	3,825,000	-	-	-	-	-
	Total 2021 Amort. of Incentive Receivable Balance	**-**		**Total Accrued 2021 Carrying Costs**		**-**	**-**	**-**	**-**	**-**
5	Q1 2022	(95,625)	3,729,375	-	3,729,375	-	17,511	50,501	68,017	85,528
6	Q2 2022	(95,625)	3,633,750	-	3,633,750	-	17,073	49,239	66,317	83,390
7	Q3 2022	(95,625)	3,538,125	-	3,538,125	-	16,635	47,976	64,616	81,252
8	Q4 2022	(95,625)	3,442,500	-	3,442,500	-	16,198	46,714	62,916	79,113
9	**Total 2022 Amort. of Incentive Receivable Balance**	**(382,500)**		**Total Accrued 2022 Carrying Costs**		**-**	**67,417**	**194,431**	**261,866**	**329,283**
10	Q1 2023	(95,625)	3,346,875	-	3,346,875	-	15,760	45,451	61,215	76,975
11	Q2 2023	(95,625)	3,251,250	-	3,251,250	-	15,322	44,189	59,515	74,837
12	Q3 2023	(95,625)	3,155,625	-	3,155,625	-	14,884	42,926	57,815	72,699
13	Q4 2023	(95,625)	3,060,000	-	3,060,000	-	14,446	41,664	56,114	70,561
	Total 2023 Amort. of Incentive Receivable Balance	**(382,500)**		**Total Accrued 2023 Carrying Costs**		**-**	**60,412**	**174,230**	**234,659**	**295,072**
14	Q1 2024	(95,625)	2,964,375	-	2,964,375	-	14,009	40,401	54,414	68,422
15	Q2 2024	(95,625)	2,868,750	-	2,868,750	-	13,571	39,139	52,713	66,284
16	Q3 2024	(95,625)	2,773,125	-	2,773,125	-	13,133	37,876	51,013	64,146
17	Q4 2024	(95,625)	2,677,500	-	2,677,500	-	12,695	36,614	49,312	62,008
	Total 2024 Amort. of Incentive Receivable Balance	**(382,500)**		**Total Accrued 2024 Carrying Costs**		**-**	**53,408**	**154,029**	**207,452**	**260,860**

Informational Purposes Only
Q1 2022 Emergncy Demand Response Incentive Receivable - Residential

Beginning Balance as of 3/31/2022	**4,612,500**				
Incentive Receivable Recovery Period (Q2 2022 - Q1 2032)	40 quarters				
Line No.	**A**	**B**	**C**	**D**	**E**
	Pre-acceptance (ST rate)	AFUDC Debt rate	AFUDC Equity rate	Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1 Carrying cost rate (annual)	**1.75%**	**1.83% B1**	**5.28% C1**	**7.11%**	**1.3468354**
2 Carrying cost rate (Quarterly)	**0.4375%**	**0.46% B2**	**1.32% C2**	**1.78%**	

Line No.		F	G		H	I		J	K	L	M
		Deferred Incentive			**Carrying Costs**						
		Amort of Incentive Receivable	**Incentive Receivable Balance**		**ADIT**	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	-		-	-	-	-	-	-	-
4	Q4 2021	-	-		-	-	-	-	-	-	-
	Total 2021 Amort. of Incentive Receivable Balance	**-**		**Total Accrued 2021 Carrying Costs**			**-**	**-**	**-**	**-**	**-**
5	Q1 2022	-	4,612,500		-	4,612,500	-	-	-	-	-
6	Q2 2022	(115,313)	4,497,188		-	4,497,188	-	21,116	60,899	82,021	103,137
7	Q3 2022	(115,313)	4,381,875		-	4,381,875	-	20,588	59,376	79,970	100,558
8	Q4 2022	(115,313)	4,266,563		-	4,266,563	-	20,060	57,854	77,920	97,980
9	**Total 2022 Amort. of Incentive Receivable Balance**	**(345,938)**		**Total Accrued 2022 Carrying Costs**			**-**	**61,764**	**178,129**	**239,911**	**301,675**
10	Q1 2023	(115,313)	4,151,250		-	4,151,250	-	19,532	56,331	75,869	95,401
11	Q2 2023	(115,313)	4,035,938		-	4,035,938	-	19,004	54,809	73,819	92,823
12	Q3 2023	(115,313)	3,920,625		-	3,920,625	-	18,477	53,286	71,768	90,245
13	Q4 2023	(115,313)	3,805,313		-	3,805,313	-	17,949	51,764	69,718	87,666
	Total 2023 Amort. of Incentive Receivable Balance	**(461,250)**		**Total Accrued 2023 Carrying Costs**			**-**	**74,962**	**216,191**	**291,174**	**366,135**
14	Q1 2024	(115,313)	3,690,000		-	3,690,000	-	17,421	50,242	67,667	85,088
15	Q2 2024	(115,313)	3,574,688		-	3,574,688	-	16,893	48,719	65,617	82,509
16	Q3 2024	(115,313)	3,459,375		-	3,459,375	-	16,365	47,197	63,566	79,931
17	Q4 2024	(115,313)	3,344,063		-	3,344,063	-	15,837	45,674	61,516	77,353
	Total 2024 Amort. of Incentive Receivable Balance	**(461,250)**		**Total Accrued 2024 Carrying Costs**			**-**	**66,515**	**191,831**	**258,365**	**324,881**

Informational Purposes Only
Q2 2022 Emergncy Demand Response Incentive Receivable - Residential

Beginning Balance as of 6/30/2022	**4,612,500**
Incentive Receivable Recovery Period (Q3 2022 - Q2 2032)	40 quarters

Line No.		**A**	**B**		**C**		**D**	**E**
		Pre-acceptance (ST rate)	AFUDC Debt rate		AFUDC Equity rate		Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1	Carrying cost rate (annual)	**1.75%**	**1.83%**	**B1**	**5.28%**	**C1**	**7.11%**	**1.3468354**
2	Carrying cost rate (Quarterly)	**0.4375%**	**0.46%**	**B2**	**1.32%**	**C2**	**1.78%**	

		F	**G**		**H**	**I**		**J**	**K**	**L**	**M**
					Carrying Costs						
					ADIT	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	-		-	-	-	-	-	-	-
4	Q4 2021	-	-		-	-	-	-	-	-	-
	Total 2021 Amort. of Incentive Receivable Balance	**-**		**Total Accrued 2021 Carrying Costs**			**-**	**-**	**-**	**-**	**-**
5	Q1 2022	-	-		-	-	-	-	-	-	-
6	Q2 2022	-	4,612,500		-	4,612,500	-	-	-	-	-
7	Q3 2022	(115,313)	4,497,188		-	4,497,188	-	21,116	60,899	82,021	103,137
8	Q4 2022	(115,313)	4,381,875		-	4,381,875	-	20,588	59,376	79,970	100,558
9	**Total 2022 Amort. of Incentive Receivable Balance**	**(230,625)**		**Total Accrued 2022 Carrying Costs**			**-**	**41,704**	**120,275**	**161,991**	**203,695**
10	Q1 2023	(115,313)	4,266,563		-	4,266,563	-	20,060	57,854	77,920	97,980
11	Q2 2023	(115,313)	4,151,250		-	4,151,250	-	19,532	56,331	75,869	95,401
12	Q3 2023	(115,313)	4,035,938		-	4,035,938	-	19,004	54,809	73,819	92,823
13	Q4 2023	(115,313)	3,920,625		-	3,920,625	-	18,477	53,286	71,768	90,245
	Total 2023 Amort. of Incentive Receivable Balance	**(461,250)**		**Total Accrued 2023 Carrying Costs**			**-**	**77,073**	**222,281**	**299,376**	**376,449**
14	Q1 2024	(115,313)	3,805,313		-	3,805,313	-	17,949	51,764	69,718	87,666
15	Q2 2024	(115,313)	3,690,000		-	3,690,000	-	17,421	50,242	67,667	85,088
16	Q3 2024	(115,313)	3,574,688		-	3,574,688	-	16,893	48,719	65,617	82,509
17	Q4 2024	(115,313)	3,459,375		-	3,459,375	-	16,365	47,197	63,566	79,931
	Total 2024 Amort. of Incentive Receivable Balance	**(461,250)**		**Total Accrued 2024 Carrying Costs**			**-**	**68,627**	**197,921**	**266,567**	**335,194**

Informational Purposes Only
Q3 2022 Emergncy Demand Response Incentive Receivable - Residential

Beginning Balance as of 9/30/2022		**4,612,500**				
Incentive Receivable Recovery Period (Q4 2022 - Q3 2032)		40 quarters				
Line No.		**A**	**B**	**C**	**D**	**E**
		Pre-acceptance (ST rate)	AFUDC Debt rate	AFUDC Equity rate	Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1	Carrying cost rate (annual)	**1.75%**	**1.83% B1**	**5.28% C1**	**7.11%**	**1.3468354**
2	Carrying cost rate (Quarterly)	**0.4375%**	**0.46% B2**	**1.32% C2**	**1.78%**	

		F	**G**	**H**	**I**		**J**	**K**	**L**	**M**
		Deferred Incentive		**Carrying Costs**						
		Amort of Incentive Receivable	**Incentive Receivable Balance**	**ADIT**	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	-	-	-	-	-	-	-	-
4	Q4 2021	-	-	-	-	-	-	-	-	-
	Total 2021 Amort. of Incentive Receivable Balance	-		**Total Accrued 2021 Carrying Costs**		-	-	-	-	-
5	Q1 2022	-	-	-	-	-	-	-	-	-
6	Q2 2022	-	-	-	-	-	-	-	-	-
7	Q3 2022	-	4,612,500	-	4,612,500	-	-	-	-	-
8	Q4 2022	(115,313)	4,497,188	-	4,497,188	-	21,116	60,899	82,021	103,137
9	**Total 2022 Amort. of Incentive Receivable Balance**	**(115,313)**		**Total Accrued 2022 Carrying Costs**		**-**	**21,116**	**60,899**	**82,021**	**103,137**
10	Q1 2023	(115,313)	4,381,875	-	4,381,875	-	20,588	59,376	79,970	100,558
11	Q2 2023	(115,313)	4,266,563	-	4,266,563	-	20,060	57,854	77,920	97,980
12	Q3 2023	(115,313)	4,151,250	-	4,151,250	-	19,532	56,331	75,869	95,401
13	Q4 2023	(115,313)	4,035,938	-	4,035,938	-	19,004	54,809	73,819	92,823
	Total 2023 Amort. of Incentive Receivable Balance	**(461,250)**		**Total Accrued 2023 Carrying Costs**		**-**	**79,185**	**228,371**	**307,578**	**386,763**
14	Q1 2024	(115,313)	3,920,625	-	3,920,625	-	18,477	53,286	71,768	90,245
15	Q2 2024	(115,313)	3,805,313	-	3,805,313	-	17,949	51,764	69,718	87,666
16	Q3 2024	(115,313)	3,690,000	-	3,690,000	-	17,421	50,242	67,667	85,088
17	Q4 2024	(115,313)	3,574,688	-	3,574,688	-	16,893	48,719	65,617	82,509
	Total 2024 Amort. of Incentive Receivable Balance	**(461,250)**		**Total Accrued 2024 Carrying Costs**		**-**	**70,739**	**204,011**	**274,769**	**345,508**

Informational Purposes Only
Q4 2022 Emergncy Demand Response Incentive Receivable - Residential

Beginning Balance as of 12/31/2022	**4,612,500**	
Incentive Receivable Recovery Period (Q1 2023 - Q4 2032)	40 quarters	

Line No.		A	B		C		D	E
		Pre-acceptance (ST rate)	AFUDC Debt rate		AFUDC Equity rate		Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1	Carrying cost rate (annual)	**1.75%**	**1.83%**	**B1**	**5.28%**	**C1**	**7.11%**	**1.3468354**
2	Carrying cost rate (Quarterly)	**0.4375%**	**0.46%**	**B2**	**1.32%**	**C2**	**1.78%**	

		F	G	H	I		J	K	L	M
		Deferred Incentive		Carrying Costs						
		Amort of Incentive Receivable	Incentive Receivable Balance	ADIT	Net of Tax Bal (G) + (H)	Pre-acceptance (ST rate)	Carrying Costs (Debt) (I) x (B2)	Carrying Costs (Equity) (I) x (C2)	Income Tax Gross-Up of Equity Carrying Costs (E) x (K)	Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)
3	Q3 2021	-	-	-	-	-	-	-	-	-
4	Q4 2021	-	-	-	-	-	-	-	-	-
	Total 2021 Amort. of Incentive Receivable Balance	-		**Total Accrued 2021 Carrying Costs**		-	-	-	-	-
5	Q1 2022	-	-	-	-	-	-	-	-	-
6	Q2 2022	-	-	-	-	-	-	-	-	-
7	Q3 2022	-	-	-	-	-	-	-	-	-
8	Q4 2022	-	4,612,500	-	4,612,500	-	-	-	-	-
9	**Total 2022 Amort. of Incentive Receivable Balance**	-		**Total Accrued 2022 Carrying Costs**		-	-	-	-	-
10	Q1 2023	(115,313)	4,497,188	-	4,497,188	-	21,116	60,899	82,021	103,137
11	Q2 2023	(115,313)	4,381,875	-	4,381,875	-	20,588	59,376	79,970	100,558
12	Q3 2023	(115,313)	4,266,563	-	4,266,563	-	20,060	57,854	77,920	97,980
13	Q4 2023	(115,313)	4,151,250	-	4,151,250	-	19,532	56,331	75,869	95,401
	Total 2023 Amort. of Incentive Receivable Balance	**(461,250)**		**Total Accrued 2023 Carrying Costs**		**-**	**81,297**	**234,461**	**315,780**	**397,076**
14	Q1 2024	(115,313)	4,035,938	-	4,035,938	-	19,004	54,809	73,819	92,823
15	Q2 2024	(115,313)	3,920,625	-	3,920,625	-	18,477	53,286	71,768	90,245
16	Q3 2024	(115,313)	3,805,313	-	3,805,313	-	17,949	51,764	69,718	87,666
17	Q4 2024	(115,313)	3,690,000	-	3,690,000	-	17,421	50,242	67,667	85,088
	Total 2024 Amort. of Incentive Receivable Balance	**(461,250)**		**Total Accrued 2024 Carrying Costs**		**-**	**72,850**	**210,101**	**282,971**	**355,822**

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Q1 2023 Emergncy Demand Response Incentive Receivable - Residential

	Beginning Balance as of 3/31/2023	**1,125,000**				
	Incentive Receivable Recovery Period (Q2 2023 - Q1 2033)	40 quarters				
Line No.		**A**	**B**	**C**	**D**	**E**
		Pre-acceptance (ST rate)	AFUDC Debt rate	AFUDC Equity rate	Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1	Carrying cost rate (annual)	**1.75%**	**1.83% B1**	**5.28% C1**	**7.11%**	**1.3468354**
2	Carrying cost rate (Quarterly)	**0.4375%**	**0.46% B2**	**1.32% C2**	**1.78%**	

		F	**G**	**H**	**I**		**J**	**K**	**L**	**M**
		Deferred Incentive		**Carrying Costs**						
Line No.		**Amort of Incentive Receivable**	**Incentive Receivable Balance**	**ADIT**	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	-	-	-	-	-	-	-	-
4	Q4 2021	-	-	-	-	-	-	-	-	-
	Total 2021 Amort. of Incentive Receivable Balance	-		**Total Accrued 2021 Carrying Costs**		-	-	-	-	-
5	Q1 2022	-	-	-	-	-	-	-	-	-
6	Q2 2022	-	-	-	-	-	-	-	-	-
7	Q3 2022	-	-	-	-	-	-	-	-	-
8	Q4 2022	-	-	-	-	-	-	-	-	-
9	**Total 2022 Amort. of Incentive Receivable Balance**	-		**Total Accrued 2022 Carrying Costs**		-	-	-	-	-
10	Q1 2023	-	1,125,000	-	1,125,000	-	-	-	-	-
11	Q2 2023	(28,125)	1,096,875	-	1,096,875	-	5,150	14,853	20,005	25,155
12	Q3 2023	(28,125)	1,068,750	-	1,068,750	-	5,021	14,482	19,505	24,526
13	Q4 2023	(28,125)	1,040,625	-	1,040,625	-	4,893	14,111	19,005	23,898
	Total 2023 Amort. of Incentive Receivable Balance	**(84,375)**		**Total Accrued 2023 Carrying Costs**		-	**15,064**	**43,446**	**58,515**	**73,579**
14	Q1 2024	(28,125)	1,012,500	-	1,012,500	-	4,764	13,739	18,505	23,269
15	Q2 2024	(28,125)	984,375	-	984,375	-	4,635	13,368	18,005	22,640
16	Q3 2024	(28,125)	956,250	-	956,250	-	4,506	12,997	17,504	22,011
17	Q4 2024	(28,125)	928,125	-	928,125	-	4,378	12,625	17,004	21,382
	Total 2024 Amort. of Incentive Receivable Balance	**(112,500)**		**Total Accrued 2024 Carrying Costs**		-	**18,283**	**52,729**	**71,018**	**89,301**

Informational Purposes Only
Q2 2023 Emergncy Demand Response Incentive Receivable - Residential

Beginning Balance as of 6/30/2023 **1,125,000**
Incentive Receivable Recovery Period (Q3 2023 - Q2 2033) 40 quarters

Line No.		A	B		C		D	E
		Pre-acceptance (ST rate)	AFUDC Debt rate		AFUDC Equity rate		Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1	Carrying cost rate (annual)	**1.75%**	**1.83%**	**B1**	**5.28%**	**C1**	**7.11%**	**1.3468354**
2	Carrying cost rate (Quarterly)	**0.4375%**	**0.46%**	**B2**	**1.32%**	**C2**	**1.78%**	

Line No.		F	G		H	I		J	K	L	M
		Deferred Incentive			Carrying Costs						
		Amort of Incentive Receivable	**Incentive Receivable Balance**		**ADIT**	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	-		-	-	-	-	-	-	-
4	Q4 2021	-	-		-	-	-	-	-	-	-
	Total 2021 Amort. of Incentive Receivable Balance	**-**		**Total Accrued 2021 Carrying Costs**			**-**	**-**	**-**	**-**	**-**
5	Q1 2022	-	-		-	-	-	-	-	-	-
6	Q2 2022	-	-		-	-	-	-	-	-	-
7	Q3 2022	-	-		-	-	-	-	-	-	-
8	Q4 2022	-	-		-	-	-	-	-	-	-
9	**Total 2022 Amort. of Incentive Receivable Balance**	**-**		**Total Accrued 2022 Carrying Costs**			**-**	**-**	**-**	**-**	**-**
10	Q1 2023	-	-		-	-	-	-	-	-	-
11	Q2 2023	-	1,125,000		-	1,125,000	-	-	-	-	-
12	Q3 2023	(28,125)	1,096,875		-	1,096,875	-	5,150	14,853	20,005	25,155
13	Q4 2023	(28,125)	1,068,750		-	1,068,750	-	5,021	14,482	19,505	24,526
	Total 2023 Amort. of Incentive Receivable Balance	**(56,250)**		**Total Accrued 2023 Carrying Costs**			**-**	**10,172**	**29,335**	**39,510**	**49,682**
14	Q1 2024	(28,125)	1,040,625		-	1,040,625	-	4,893	14,111	19,005	23,898
15	Q2 2024	(28,125)	1,012,500		-	1,012,500	-	4,764	13,739	18,505	23,269
16	Q3 2024	(28,125)	984,375		-	984,375	-	4,635	13,368	18,005	22,640
17	Q4 2024	(28,125)	956,250		-	956,250	-	4,506	12,997	17,504	22,011
	Total 2024 Amort. of Incentive Receivable Balance	**(112,500)**		**Total Accrued 2024 Carrying Costs**			**-**	**18,798**	**54,215**	**73,018**	**91,817**

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Q3 2023 Emergncy Demand Response Incentive Receivable - Residential

Beginning Balance as of 9/30/2023 — **1,125,000**
Incentive Receivable Recovery Period (Q4 2023 - Q3 2033) — 40 quarters

Line No.		A	B		C		D	E
		Pre-acceptance (ST rate)	AFUDC Debt rate		AFUDC Equity rate		Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1	Carrying cost rate (annual)	**1.75%**	**1.83%**	**B1**	**5.28%**	**C1**	**7.11%**	**1.3468354**
2	Carrying cost rate (Quarterly)	**0.4375%**	**0.46%**	**B2**	**1.32%**	**C2**	**1.78%**	

Line No.		F	G		H	I		J	K	L	M
		Deferred Incentive			**Carrying Costs**						
		Amort of Incentive Receivable	**Incentive Receivable Balance**		**ADIT**	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	-		-	-	-	-	-	-	-
4	Q4 2021	-	-		-	-	-	-	-	-	-
	Total 2021 Amort. of Incentive Receivable Balance	**-**		**Total Accrued 2021 Carrying Costs**			**-**	**-**	**-**	**-**	**-**
5	Q1 2022	-	-		-	-	-	-	-	-	-
6	Q2 2022	-	-		-	-	-	-	-	-	-
7	Q3 2022	-	-		-	-	-	-	-	-	-
8	Q4 2022	-	-		-	-	-	-	-	-	-
9	**Total 2022 Amort. of Incentive Receivable Balance**	**-**		**Total Accrued 2022 Carrying Costs**			**-**	**-**	**-**	**-**	**-**
10	Q1 2023	-	-		-	-	-	-	-	-	-
11	Q2 2023	-	-		-	-	-	-	-	-	-
12	Q3 2023	-	1,125,000		-	1,125,000	-	-	-	-	-
13	Q4 2023	(28,125)	1,096,875		-	1,096,875	-	5,150	14,853	20,005	25,155
	Total 2023 Amort. of Incentive Receivable Balance	**(28,125)**		**Total Accrued 2023 Carrying Costs**			**-**	**5,150**	**14,853**	**20,005**	**25,155**
14	Q1 2024	(28,125)	1,068,750		-	1,068,750	-	5,021	14,482	19,505	24,526
15	Q2 2024	(28,125)	1,040,625		-	1,040,625	-	4,893	14,111	19,005	23,898
16	Q3 2024	(28,125)	1,012,500		-	1,012,500	-	4,764	13,739	18,505	23,269
17	Q4 2024	(28,125)	984,375		-	984,375	-	4,635	13,368	18,005	22,640
	Total 2024 Amort. of Incentive Receivable Balance	**(112,500)**		**Total Accrued 2024 Carrying Costs**			**-**	**19,313**	**55,700**	**75,019**	**94,332**

Informational Purposes Only
Q4 2023 Emergncy Demand Response Incentive Receivable - Residential

Beginning Balance as of 12/31/2023	**1,125,000**	
Incentive Receivable Recovery Period (Q1 2024 - Q4 2033)	40 quarters	

Line No.		A	B	C	D	E
		Pre-acceptance (ST rate)	AFUDC Debt rate	AFUDC Equity rate	Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1	Carrying cost rate (annual)	**1.75%**	**1.83% B1**	**5.28% C1**	**7.11%**	**1.3468354**
2	Carrying cost rate (Quarterly)	**0.4375%**	**0.46% B2**	**1.32% C2**	**1.78%**	

Line No.		F	G	H	I		J	K	L	M
		Deferred Incentive		**Carrying Costs**						
		Amort of Incentive Receivable	**Incentive Receivable Balance**	**ADIT**	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	-	-	-	-	-	-	-	-
4	Q4 2021	-	-	-	-	-	-	-	-	-
	Total 2021 Amort. of Incentive Receivable Balance	-		**Total Accrued 2021 Carrying Costs**		-	-	-	-	-
5	Q1 2022	-	-	-	-	-	-	-	-	-
6	Q2 2022	-	-	-	-	-	-	-	-	-
7	Q3 2022	-	-	-	-	-	-	-	-	-
8	Q4 2022	-	-	-	-	-	-	-	-	-
9	**Total 2022 Amort. of Incentive Receivable Balance**	-		**Total Accrued 2022 Carrying Costs**		-	-	-	-	-
10	Q1 2023	-	-	-	-	-	-	-	-	-
11	Q2 2023	-	-	-	-	-	-	-	-	-
12	Q3 2023	-	-	-	-	-	-	-	-	-
13	Q4 2023	-	1,125,000	-	1,125,000	-	-	-	-	-
	Total 2023 Amort. of Incentive Receivable Balance	-		**Total Accrued 2023 Carrying Costs**		-	-	-	-	-
14	Q1 2024	(28,125)	1,096,875	-	1,096,875	-	5,150	14,853	20,005	25,155
15	Q2 2024	(28,125)	1,068,750	-	1,068,750	-	5,021	14,482	19,505	24,526
16	Q3 2024	(28,125)	1,040,625	-	1,040,625	-	4,893	14,111	19,005	23,898
17	Q4 2024	(28,125)	1,012,500	-	1,012,500	-	4,764	13,739	18,505	23,269
	Total 2024 Amort. of Incentive Receivable Balance	**(112,500)**		**Total Accrued 2024 Carrying Costs**		-	**19,828**	**57,185**	**77,019**	**96,848**

Informational Purposes Only
Q3 2021 Emergncy Demand Response Incentive Receivable - Commercial

Beginning Balance as of 6/30/2021 — **425,000**
Incentive Receivable Recovery Period (Jan 2022 - Dec 2031) — 40 quarters

Line No.		A	B	C	D	E
		Pre-acceptance (ST rate)	AFUDC Debt rate	AFUDC Equity rate	Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1	Carrying cost rate (annual)	**1.75%**	**1.83% B1**	**5.28% C1**	**7.11%**	**1.3468354**
2	Carrying cost rate (Quarterly)	**0.4375%**	**0.46% B2**	**1.32% C2**	**1.78%**	

Line No.		F	G	H	I		J	K	L	M
		Deferred Incentive		Carrying Costs						
		Amort of Incentive Receivable	**Incentive Receivable Balance**	**ADIT**	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	425,000	-	425,000	-	-	-	-	-
4	Q4 2021	(10,625)	414,375	-	414,375	-	1,946	5,611	7,557	9,503
	Total 2021 Amort. of Incentive Receivable Balance	**(10,625)**			**Total Accrued 2021 Carrying Costs**	**-**	**1,946**	**5,611**	**7,557**	**9,503**
5	Q1 2022	(10,625)	403,750	-	403,750	-	1,897	5,471	7,369	9,266
6	Q2 2022	(10,625)	393,125	-	393,125	-	1,848	5,331	7,180	9,028
7	Q3 2022	(10,625)	382,500	-	382,500	-	1,800	5,190	6,991	8,790
8	Q4 2022	(10,625)	371,875	-	371,875	-	1,751	5,050	6,802	8,553
9	**Total 2022 Amort. of Incentive Receivable Balance**	**(42,500)**			**Total Accrued 2022 Carrying Costs**	**-**	**7,296**	**21,042**	**28,340**	**35,637**
10	Q1 2023	(10,625)	361,250	-	361,250	-	1,702	4,910	6,613	8,315
11	Q2 2023	(10,625)	350,625	-	350,625	-	1,654	4,770	6,424	8,078
12	Q3 2023	(10,625)	340,000	-	340,000	-	1,605	4,629	6,235	7,840
13	Q4 2023	(10,625)	329,375	-	329,375	-	1,557	4,489	6,046	7,602
	Total 2023 Amort. of Incentive Receivable Balance	**(42,500)**			**Total Accrued 2023 Carrying Costs**	**-**	**6,518**	**18,798**	**25,318**	**31,835**
14	Q1 2024	(10,625)	318,750	-	318,750	-	1,508	4,349	5,857	7,365
15	Q2 2024	(10,625)	308,125	-	308,125	-	1,459	4,208	5,668	7,127
16	Q3 2024	(10,625)	297,500	-	297,500	-	1,411	4,068	5,479	6,890
17	Q4 2024	(10,625)	286,875	-	286,875	-	1,362	3,928	5,290	6,652
	Total 2024 Amort. of Incentive Receivable Balance	**(42,500)**			**Total Accrued 2024 Carrying Costs**	**-**	**5,740**	**16,553**	**22,295**	**28,034**

Informational Purposes Only
Q4 2021 Emergncy Demand Response Incentive Receivable - Commercial

Beginning Balance as of 12/31/2021	**425,000**
Incentive Receivable Recovery Period (Jan 2022 - Dec 2031)	40 quarters

Line No.		**A**	**B**		**C**		**D**	**E**
		Pre-acceptance (ST rate)	AFUDC Debt rate		AFUDC Equity rate		Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1	Carrying cost rate (annual)	**1.75%**	**1.83%**	**B1**	**5.28%**	**C1**	**7.11%**	**1.3468354**
2	Carrying cost rate (Quarterly)	**0.4375%**	**0.46%**	**B2**	**1.32%**	**C2**	**1.78%**	

		F	**G**	**H**	**I**		**J**	**K**	**L**	**M**
				Carrying Costs						
				ADIT	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	-	-	-	-	-	-	-	-
4	Q4 2021	-	425,000	-	425,000	-	-	-	-	-
	Total 2021 Amort. of Incentive Receivable Balance	**-**		**Total Accrued 2021 Carrying Costs**		**-**	**-**	**-**	**-**	**-**
5	Q1 2022	(10,625)	414,375	-	414,375	-	1,946	5,611	7,557	9,503
6	Q2 2022	(10,625)	403,750	-	403,750	-	1,897	5,471	7,369	9,266
7	Q3 2022	(10,625)	393,125	-	393,125	-	1,848	5,331	7,180	9,028
8	Q4 2022	(10,625)	382,500	-	382,500	-	1,800	5,190	6,991	8,790
9	**Total 2022 Amort. of Incentive Receivable Balance**	**(42,500)**		**Total Accrued 2022 Carrying Costs**		**-**	**7,491**	**21,603**	**29,096**	**36,587**
10	Q1 2023	(10,625)	371,875	-	371,875	-	1,751	5,050	6,802	8,553
11	Q2 2023	(10,625)	361,250	-	361,250	-	1,702	4,910	6,613	8,315
12	Q3 2023	(10,625)	350,625	-	350,625	-	1,654	4,770	6,424	8,078
13	Q4 2023	(10,625)	340,000	-	340,000	-	1,605	4,629	6,235	7,840
	Total 2023 Amort. of Incentive Receivable Balance	**(42,500)**		**Total Accrued 2023 Carrying Costs**		**-**	**6,712**	**19,359**	**26,073**	**32,786**
14	Q1 2024	(10,625)	329,375	-	329,375	-	1,557	4,489	6,046	7,602
15	Q2 2024	(10,625)	318,750	-	318,750	-	1,508	4,349	5,857	7,365
16	Q3 2024	(10,625)	308,125	-	308,125	-	1,459	4,208	5,668	7,127
17	Q4 2024	(10,625)	297,500	-	297,500	-	1,411	4,068	5,479	6,890
	Total 2024 Amort. of Incentive Receivable Balance	**(42,500)**		**Total Accrued 2024 Carrying Costs**		**-**	**5,934**	**17,114**	**23,050**	**28,984**

Informational Purposes Only
Q1 2022 Emergncy Demand Response Incentive Receivable - Commercial

Beginning Balance as of 3/31/2022	**512,500**	
Incentive Receivable Recovery Period (Q2 2022 - Q1 2032)	40 quarters	

Line No.		A	B	C	D	E
		Pre-acceptance (ST rate)	AFUDC Debt rate	AFUDC Equity rate	Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1	Carrying cost rate (annual)	**1.75%**	**1.83% B1**	**5.28% C1**	**7.11%**	**1.3468354**
2	Carrying cost rate (Quarterly)	**0.4375%**	**0.46% B2**	**1.32% C2**	**1.78%**	

Line No.		F	G		H	I		J	K	L	M
		Deferred Incentive			**Carrying Costs**						
		Amort of Incentive Receivable	**Incentive Receivable Balance**		**ADIT**	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	-		-	-	-	-	-	-	-
4	Q4 2021	-	-		-	-	-	-	-	-	-
	Total 2021 Amort. of Incentive Receivable Balance	**-**		**Total Accrued 2021 Carrying Costs**			**-**	**-**	**-**	**-**	**-**
5	Q1 2022	-	512,500		-	512,500	-	-	-	-	-
6	Q2 2022	(12,813)	499,688		-	499,688	-	2,346	6,767	9,113	11,460
7	Q3 2022	(12,813)	486,875		-	486,875	-	2,288	6,597	8,886	11,173
8	Q4 2022	(12,813)	474,063		-	474,063	-	2,229	6,428	8,658	10,887
9	**Total 2022 Amort. of Incentive Receivable Balance**	**(38,438)**		**Total Accrued 2022 Carrying Costs**			**-**	**6,863**	**19,792**	**26,657**	**33,519**
10	Q1 2023	(12,813)	461,250		-	461,250	-	2,170	6,259	8,430	10,600
11	Q2 2023	(12,813)	448,438		-	448,438	-	2,112	6,090	8,202	10,314
12	Q3 2023	(12,813)	435,625		-	435,625	-	2,053	5,921	7,974	10,027
13	Q4 2023	(12,813)	422,813		-	422,813	-	1,994	5,752	7,746	9,741
	Total 2023 Amort. of Incentive Receivable Balance	**(51,250)**		**Total Accrued 2023 Carrying Costs**			**-**	**8,329**	**24,021**	**32,353**	**40,682**
14	Q1 2024	(12,813)	410,000		-	410,000	-	1,936	5,582	7,519	9,454
15	Q2 2024	(12,813)	397,188		-	397,188	-	1,877	5,413	7,291	9,168
16	Q3 2024	(12,813)	384,375		-	384,375	-	1,818	5,244	7,063	8,881
17	Q4 2024	(12,813)	371,563		-	371,563	-	1,760	5,075	6,835	8,595
	Total 2024 Amort. of Incentive Receivable Balance	**(51,250)**		**Total Accrued 2024 Carrying Costs**			**-**	**7,391**	**21,315**	**28,707**	**36,098**

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Q2 2022 Emergncy Demand Response Incentive Receivable - Commercial

Beginning Balance as of 6/30/2022		**512,500**				
Incentive Receivable Recovery Period (Q3 2022 - Q2 2032)		40 quarters				
Line No.		**A**	**B**	**C**	**D**	**E**
		Pre-acceptance (ST rate)	AFUDC Debt rate	AFUDC Equity rate	Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1	Carrying cost rate (annual)	**1.75%**	**1.83% B1**	**5.28% C1**	**7.11%**	**1.3468354**
2	Carrying cost rate (Quarterly)	**0.4375%**	**0.46% B2**	**1.32% C2**	**1.78%**	

		F	G	H	I		J	K	L	M
		Deferred Incentive		**Carrying Costs**						
		Amort of Incentive Receivable	**Incentive Receivable Balance**	**ADIT**	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	-	-	-	-	-	-	-	-
4	Q4 2021	-	-	-	-	-	-	-	-	-
	Total 2021 Amort. of Incentive Receivable Balance	**-**		**Total Accrued 2021 Carrying Costs**		**-**	**-**	**-**	**-**	**-**
5	Q1 2022	-	-	-	-	-	-	-	-	-
6	Q2 2022	-	512,500	-	512,500	-	-	-	-	-
7	Q3 2022	(12,813)	499,688	-	499,688	-	2,346	6,767	9,113	11,460
8	Q4 2022	(12,813)	486,875	-	486,875	-	2,288	6,597	8,886	11,173
9	**Total 2022 Amort. of Incentive Receivable Balance**	**(25,625)**		**Total Accrued 2022 Carrying Costs**		**-**	**4,634**	**13,364**	**17,999**	**22,633**
10	Q1 2023	(12,813)	474,063	-	474,063	-	2,229	6,428	8,658	10,887
11	Q2 2023	(12,813)	461,250	-	461,250	-	2,170	6,259	8,430	10,600
12	Q3 2023	(12,813)	448,438	-	448,438	-	2,112	6,090	8,202	10,314
13	Q4 2023	(12,813)	435,625	-	435,625	-	2,053	5,921	7,974	10,027
	Total 2023 Amort. of Incentive Receivable Balance	**(51,250)**		**Total Accrued 2023 Carrying Costs**		**-**	**8,564**	**24,698**	**33,264**	**41,828**
14	Q1 2024	(12,813)	422,813	-	422,813	-	1,994	5,752	7,746	9,741
15	Q2 2024	(12,813)	410,000	-	410,000	-	1,936	5,582	7,519	9,454
16	Q3 2024	(12,813)	397,188	-	397,188	-	1,877	5,413	7,291	9,168
17	Q4 2024	(12,813)	384,375	-	384,375	-	1,818	5,244	7,063	8,881
	Total 2024 Amort. of Incentive Receivable Balance	**(51,250)**		**Total Accrued 2024 Carrying Costs**		**-**	**7,625**	**21,991**	**29,619**	**37,244**

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Q3 2022 Emergncy Demand Response Incentive Receivable - Commercial

Beginning Balance as of 9/30/2022	**512,500**				
Incentive Receivable Recovery Period (Q4 2022 - Q3 2032)	40 quarters				
Line No.	**A**	**B**	**C**	**D**	**E**
	Pre-acceptance (ST rate)	AFUDC Debt rate	AFUDC Equity rate	Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1 Carrying cost rate (annual)	**1.75%**	**1.83% B1**	**5.28% C1**	**7.11%**	**1.3468354**
2 Carrying cost rate (Quarterly)	**0.4375%**	**0.46% B2**	**1.32% C2**	**1.78%**	

Line No.		F	G		H	I		J	K	L	M
		Deferred Incentive			**Carrying Costs**						
		Amort of Incentive Receivable	**Incentive Receivable Balance**		**ADIT**	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	-		-	-	-	-	-	-	-
4	Q4 2021	-	-		-	-	-	-	-	-	-
	Total 2021 Amort. of Incentive Receivable Balance	**-**		**Total Accrued 2021 Carrying Costs**			**-**	**-**	**-**	**-**	**-**
5	Q1 2022	-	-		-	-	-	-	-	-	-
6	Q2 2022	-	-		-	-	-	-	-	-	-
7	Q3 2022	-	512,500		-	512,500	-	-	-	-	-
8	Q4 2022	(12,813)	499,688		-	499,688	-	2,346	6,767	9,113	11,460
9	**Total 2022 Amort. of Incentive Receivable Balance**	**(12,813)**		**Total Accrued 2022 Carrying Costs**			**-**	**2,346**	**6,767**	**9,113**	**11,460**
10	Q1 2023	(12,813)	486,875		-	486,875	-	2,288	6,597	8,886	11,173
11	Q2 2023	(12,813)	474,063		-	474,063	-	2,229	6,428	8,658	10,887
12	Q3 2023	(12,813)	461,250		-	461,250	-	2,170	6,259	8,430	10,600
13	Q4 2023	(12,813)	448,438		-	448,438	-	2,112	6,090	8,202	10,314
	Total 2023 Amort. of Incentive Receivable Balance	**(51,250)**		**Total Accrued 2023 Carrying Costs**			**-**	**8,798**	**25,375**	**34,175**	**42,974**
14	Q1 2024	(12,813)	435,625		-	435,625	-	2,053	5,921	7,974	10,027
15	Q2 2024	(12,813)	422,813		-	422,813	-	1,994	5,752	7,746	9,741
16	Q3 2024	(12,813)	410,000		-	410,000	-	1,936	5,582	7,519	9,454
17	Q4 2024	(12,813)	397,188		-	397,188	-	1,877	5,413	7,291	9,168
	Total 2024 Amort. of Incentive Receivable Balance	**(51,250)**		**Total Accrued 2024 Carrying Costs**			**-**	**7,860**	**22,668**	**30,530**	**38,390**

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Q4 2022 Emergncy Demand Response Incentive Receivable - Commercial

Beginning Balance as of 12/31/2022		**512,500**				
Incentive Receivable Recovery Period (Q1 2023 - Q4 2032)		40 quarters				
Line No.		**A**	**B**	**C**	**D**	**E**
		Pre-acceptance (ST rate)	AFUDC Debt rate	AFUDC Equity rate	Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1	Carrying cost rate (annual)	**1.75%**	**1.83%** **B1**	**5.28%** **C1**	**7.11%**	**1.3468354**
2	Carrying cost rate (Quarterly)	**0.4375%**	**0.46%** **B2**	**1.32%** **C2**	**1.78%**	

Line No.		F	G		H	I		J	K	L	M
		Deferred Incentive			**Carrying Costs**						
		Amort of Incentive Receivable	**Incentive Receivable Balance**		**ADIT**	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	-		-	-	-	-	-	-	-
4	Q4 2021	-	-		-	-	-	-	-	-	-
	Total 2021 Amort. of Incentive Receivable Balance	**-**		**Total Accrued 2021 Carrying Costs**			**-**	**-**	**-**	**-**	**-**
5	Q1 2022	-	-		-	-	-	-	-	-	-
6	Q2 2022	-	-		-	-	-	-	-	-	-
7	Q3 2022	-	-		-	-	-	-	-	-	-
8	Q4 2022	-	512,500		-	512,500	-	-	-	-	-
9	**Total 2022 Amort. of Incentive Receivable Balance**	**-**		**Total Accrued 2022 Carrying Costs**			**-**	**-**	**-**	**-**	**-**
10	Q1 2023	(12,813)	499,688		-	499,688	-	2,346	6,767	9,113	11,460
11	Q2 2023	(12,813)	486,875		-	486,875	-	2,288	6,597	8,886	11,173
12	Q3 2023	(12,813)	474,063		-	474,063	-	2,229	6,428	8,658	10,887
13	Q4 2023	(12,813)	461,250		-	461,250	-	2,170	6,259	8,430	10,600
	Total 2023 Amort. of Incentive Receivable Balance	**(51,250)**		**Total Accrued 2023 Carrying Costs**			**-**	**9,033**	**26,051**	**35,087**	**44,120**
14	Q1 2024	(12,813)	448,438		-	448,438	-	2,112	6,090	8,202	10,314
15	Q2 2024	(12,813)	435,625		-	435,625	-	2,053	5,921	7,974	10,027
16	Q3 2024	(12,813)	422,813		-	422,813	-	1,994	5,752	7,746	9,741
17	Q4 2024	(12,813)	410,000		-	410,000	-	1,936	5,582	7,519	9,454
	Total 2024 Amort. of Incentive Receivable Balance	**(51,250)**		**Total Accrued 2024 Carrying Costs**			**-**	**8,094**	**23,345**	**31,441**	**39,536**

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Q1 2023 Emergncy Demand Response Incentive Receivable - Commercial

Beginning Balance as of 3/31/2023	**125,000**
Incentive Receivable Recovery Period (Q2 2023 - Q1 2033)	40 quarters

Line No.		**A**	**B**		**C**		**D**	**E**
		Pre-acceptance (ST rate)	AFUDC Debt rate		AFUDC Equity rate		Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1	Carrying cost rate (annual)	**1.75%**	**1.83%**	**B1**	**5.28%**	**C1**	**7.11%**	**1.3468354**
2	Carrying cost rate (Quarterly)	**0.4375%**	**0.46%**	**B2**	**1.32%**	**C2**	**1.78%**	

		F	**G**	**H**	**I**		**J**	**K**	**L**	**M**
		Deferred Incentive		**Carrying Costs**						
Line No.		**Amort of Incentive Receivable**	**Incentive Receivable Balance**	**ADIT**	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	-	-	-	-	-	-	-	-
4	Q4 2021	-	-	-	-	-	-	-	-	-
	Total 2021 Amort. of Incentive Receivable Balance	-		**Total Accrued 2021 Carrying Costs**		-	-	-	-	-
5	Q1 2022	-	-	-	-	-	-	-	-	-
6	Q2 2022	-	-	-	-	-	-	-	-	-
7	Q3 2022	-	-	-	-	-	-	-	-	-
8	Q4 2022	-	-	-	-	-	-	-	-	-
9	**Total 2022 Amort. of Incentive Receivable Balance**	-		**Total Accrued 2022 Carrying Costs**		-	-	-	-	-
10	Q1 2023	-	125,000	-	125,000	-	-	-	-	-
11	Q2 2023	(3,125)	121,875	-	121,875	-	572	1,650	2,223	2,795
12	Q3 2023	(3,125)	118,750	-	118,750	-	558	1,609	2,167	2,725
13	Q4 2023	(3,125)	115,625	-	115,625	-	544	1,568	2,112	2,655
	Total 2023 Amort. of Incentive Receivable Balance	**(9,375)**		**Total Accrued 2023 Carrying Costs**		-	**1,674**	**4,827**	**6,502**	**8,175**
14	Q1 2024	(3,125)	112,500	-	112,500	-	529	1,527	2,056	2,585
15	Q2 2024	(3,125)	109,375	-	109,375	-	515	1,485	2,001	2,516
16	Q3 2024	(3,125)	106,250	-	106,250	-	501	1,444	1,945	2,446
17	Q4 2024	(3,125)	103,125	-	103,125	-	486	1,403	1,889	2,376
	Total 2024 Amort. of Incentive Receivable Balance	**(12,500)**		**Total Accrued 2024 Carrying Costs**		-	**2,031**	**5,859**	**7,891**	**9,922**

Informational Purposes Only
Q2 2023 Emergncy Demand Response Incentive Receivable - Commercial

Beginning Balance as of 6/30/2023	**125,000**
Incentive Receivable Recovery Period (Q3 2023 - Q2 2033)	40 quarters

Line No.		A	B		C		D	E
		Pre-acceptance (ST rate)	AFUDC Debt rate		AFUDC Equity rate		Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1	Carrying cost rate (annual)	**1.75%**	**1.83%**	**B1**	**5.28%**	**C1**	**7.11%**	**1.3468354**
2	Carrying cost rate (Quarterly)	**0.4375%**	**0.46%**	**B2**	**1.32%**	**C2**	**1.78%**	

Line No.		F	G	H	I		J	K	L	M
		Deferred Incentive		**Carrying Costs**						
		Amort of Incentive Receivable	**Incentive Receivable Balance**	**ADIT**	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	-	-	-	-	-	-	-	-
4	Q4 2021	-	-	-	-	-	-	-	-	-
	Total 2021 Amort. of Incentive Receivable Balance	-		**Total Accrued 2021 Carrying Costs**		-	-	-	-	-
5	Q1 2022	-	-	-	-	-	-	-	-	-
6	Q2 2022	-	-	-	-	-	-	-	-	-
7	Q3 2022	-	-	-	-	-	-	-	-	-
8	Q4 2022	-	-	-	-	-	-	-	-	-
9	**Total 2022 Amort. of Incentive Receivable Balance**	-		**Total Accrued 2022 Carrying Costs**		-	-	-	-	-
10	Q1 2023	-	-	-	-	-	-	-	-	-
11	Q2 2023	-	125,000	-	125,000	-	-	-	-	-
12	Q3 2023	(3,125)	121,875	-	121,875	-	572	1,650	2,223	2,795
13	Q4 2023	(3,125)	118,750	-	118,750	-	558	1,609	2,167	2,725
	Total 2023 Amort. of Incentive Receivable Balance	**(6,250)**		**Total Accrued 2023 Carrying Costs**		-	**1,130**	**3,259**	**4,390**	**5,520**
14	Q1 2024	(3,125)	115,625	-	115,625	-	544	1,568	2,112	2,655
15	Q2 2024	(3,125)	112,500	-	112,500	-	529	1,527	2,056	2,585
16	Q3 2024	(3,125)	109,375	-	109,375	-	515	1,485	2,001	2,516
17	Q4 2024	(3,125)	106,250	-	106,250	-	501	1,444	1,945	2,446
	Total 2024 Amort. of Incentive Receivable Balance	**(12,500)**		**Total Accrued 2024 Carrying Costs**		-	**2,089**	**6,024**	**8,113**	**10,202**

Informational Purposes Only
Q3 2023 Emergncy Demand Response Incentive Receivable - Commercial

Beginning Balance as of 9/30/2023	**125,000**	
Incentive Receivable Recovery Period (Q4 2023 - Q3 2033)	40 quarters	

Line No.		A	B		C		D	E
		Pre-acceptance (ST rate)	AFUDC Debt rate		AFUDC Equity rate		Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1	Carrying cost rate (annual)	**1.75%**	**1.83%**	**B1**	**5.28%**	**C1**	**7.11%**	**1.3468354**
2	Carrying cost rate (Quarterly)	**0.4375%**	**0.46%**	**B2**	**1.32%**	**C2**	**1.78%**	

		F	G	H	I		J	K	L	M
		Deferred Incentive		**Carrying Costs**						
		Amort of Incentive Receivable	**Incentive Receivable Balance**	**ADIT**	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	-	-	-	-	-	-	-	-
4	Q4 2021	-	-	-	-	-	-	-	-	-
	Total 2021 Amort. of Incentive Receivable Balance	**-**		**Total Accrued 2021 Carrying Costs**		**-**	**-**	**-**	**-**	**-**
5	Q1 2022	-	-	-	-	-	-	-	-	-
6	Q2 2022	-	-	-	-	-	-	-	-	-
7	Q3 2022	-	-	-	-	-	-	-	-	-
8	Q4 2022	-	-	-	-	-	-	-	-	-
9	**Total 2022 Amort. of Incentive Receivable Balance**	**-**		**Total Accrued 2022 Carrying Costs**		**-**	**-**	**-**	**-**	**-**
10	Q1 2023	-	-	-	-	-	-	-	-	-
11	Q2 2023	-	-	-	-	-	-	-	-	-
12	Q3 2023	-	125,000	-	125,000	-	-	-	-	-
13	Q4 2023	(3,125)	121,875	-	121,875	-	572	1,650	2,223	2,795
	Total 2023 Amort. of Incentive Receivable Balance	**(3,125)**		**Total Accrued 2023 Carrying Costs**		**-**	**572**	**1,650**	**2,223**	**2,795**
14	Q1 2024	(3,125)	118,750	-	118,750	-	558	1,609	2,167	2,725
15	Q2 2024	(3,125)	115,625	-	115,625	-	544	1,568	2,112	2,655
16	Q3 2024	(3,125)	112,500	-	112,500	-	529	1,527	2,056	2,585
17	Q4 2024	(3,125)	109,375	-	109,375	-	515	1,485	2,001	2,516
	Total 2024 Amort. of Incentive Receivable Balance	**(12,500)**		**Total Accrued 2024 Carrying Costs**		**-**	**2,146**	**6,189**	**8,335**	**10,481**

Informational Purposes Only
Q4 2023 Emergncy Demand Response Incentive Receivable - Commercial

		A	B		C		D	E
Beginning Balance as of 12/31/2023		**125,000**						
Incentive Receivable Recovery Period (Q1 2024 - Q4 2033)		40 quarters						
Line No.		Pre-acceptance (ST rate)	AFUDC Debt rate		AFUDC Equity rate		Total	Gross-Up Factor (1/(1-Effective Tax Rate))
1	Carrying cost rate (annual)	**1.75%**	**1.83%**	**B1**	**5.28%**	**C1**	**7.11%**	**1.3468354**
2	Carrying cost rate (Quarterly)	**0.4375%**	**0.46%**	**B2**	**1.32%**	**C2**	**1.78%**	

		F	G	H	I		J	K	L	M
		Deferred Incentive		**Carrying Costs**						
Line No.		**Amort of Incentive Receivable**	**Incentive Receivable Balance**	**ADIT**	**Net of Tax Bal (G) + (H)**	**Pre-acceptance (ST rate)**	**Carrying Costs (Debt) (I) x (B2)**	**Carrying Costs (Equity) (I) x (C2)**	**Income Tax Gross-Up of Equity Carrying Costs (E) x (K)**	**Total Carrying Costs (Debt + Grossed up Equity) (J) + (L)**
3	Q3 2021	-	-	-	-	-	-	-	-	-
4	Q4 2021	-	-	-	-	-	-	-	-	-
	Total 2021 Amort. of Incentive Receivable Balance	-		**Total Accrued 2021 Carrying Costs**		-	-	-	-	-
5	Q1 2022	-	-	-	-	-	-	-	-	-
6	Q2 2022	-	-	-	-	-	-	-	-	-
7	Q3 2022	-	-	-	-	-	-	-	-	-
8	Q4 2022	-	-	-	-	-	-	-	-	-
9	**Total 2022 Amort. of Incentive Receivable Balance**	-		**Total Accrued 2022 Carrying Costs**		-	-	-	-	-
10	Q1 2023	-	-	-	-	-	-	-	-	-
11	Q2 2023	-	-	-	-	-	-	-	-	-
12	Q3 2023	-	-	-	-	-	-	-	-	-
13	Q4 2023	-	125,000	-	125,000	-	-	-	-	-
	Total 2023 Amort. of Incentive Receivable Balance	-		**Total Accrued 2023 Carrying Costs**		-	-	-	-	-
14	Q1 2024	(3,125)	121,875	-	121,875	-	572	1,650	2,223	2,795
15	Q2 2024	(3,125)	118,750	-	118,750	-	558	1,609	2,167	2,725
16	Q3 2024	(3,125)	115,625	-	115,625	-	544	1,568	2,112	2,655
17	Q4 2024	(3,125)	112,500	-	112,500	-	529	1,527	2,056	2,585
	Total 2024 Amort. of Incentive Receivable Balance	**(12,500)**		**Total Accrued 2024 Carrying Costs**		**-**	**2,203**	**6,354**	**8,558**	**10,761**

CERTIFICATE OF SERVICE

I hereby certify that on this date, a copy of the foregoing document, together with this Certificate of Service, were duly served upon the following parties as set forth below:[1]

Party	Email
Dean Nishina Executive Director Division of Consumer Advocacy Department of Commerce and Consumer Affairs 335 Merchant Street, Room 326 Honolulu, Hawaii 96813	dnishina@dcca.hawaii.gov consumeradvocate@dcca.hawaii.gov
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DATED: Honolulu, Hawai‘i, June 18, 2021.

/s/ Kyle Kawata
Kyle Kawata
HAWAIIAN ELECTRIC COMPANY, INC.

[1] As stated in Order No. 37043, *Setting Forth Public Utilities Commission Emergency Filing and Service Procedures related to COVID-19* (non-docketed), issued on March 13, 2020, at 11:

> Service of all documents filed by any parties, participants, utilities, stakeholders and/or other entities or individuals shall be via email. All entities making filings before the commission will be required to supply an email address that can be used for service. Any Certificates of Service for docketed or other matters that previously had listed the entity's name and the physical address where a document was served via first-class mail, shall instead reflect the entity's representative's name, entity name, email address where served, as well as the date of service.