III. IMPACT ISSUES

A. ISSUE #4: WHAT IMPACTS, IF ANY, WILL DISTRIBUTED GENERATION HAVE ON HAWAII'S ELECTRIC TRANSMISSION AND DISTRIBUTION SYSTEMS AND MARKET?

1. Impacts On T&D Systems

Each of the previously discussed seven types of DG applications will impact the transmission distribution ("T&D") system differently. For instance, customer-sited generation operated in parallel with the utility grid and interconnected according to Tariff Rule 14.H, and off-grid, customer-sited generation, which does not use the utility grid, will have different impacts on the T&D system. HECO T-4 at 2.

a. Potential Benefits

In concept, DG could benefit the T&D system by deferring the need for certain T&D facilities such as lines and transformers, which may be needed to avoid overloads under contingency and projected peak conditions. With the addition and reliable operation of enough DG to reduce peak load, the deferral benefit might be realized. Factors such as the diversity of DG installations, issues, T&D peak load planning, and the customer's commitment to the operation and maintenance of DG will affect the extent to which these T&D facilities can be deferred. See HECO T-4 at 13-17, Responses to HREA-HECO-IR-12; COM-HECO-SOP-IR-3; COM-HECO-DT-IR-26.

DG can also reduce system transmission and distribution line losses. In addition, DG could provide voltage support as explained in HECO's Preliminary Statement of Position at 20 and HECO Companies' Response to HREA-HECO-T-4-IR-6. HECO Companies' Response to PUC-IR-12; Response to COM-HECO-DT-IR-28.

b. Potential Negative System Impacts

Depending on factors such as the location of the DG unit, however, DG may increase the risk of voltage regulation problems or may impact the utility's protection system, which can result in unintended islanding. The impact of DG located at customer facilities is dependent on location specific issues such as: the configuration of the distribution system, radial vs. network, length of distribution lines, penetration of distributed generation on the primary circuit and the back up circuit, reliability and redundancy of customer systems, synchronous or induction generation, grounding of transformers and other equipment, and short circuit characteristics of the distribution circuit. HECO Companies' Response to PUC-IR-13.

Rule 14.H. specifies levels of DG penetration that trigger additional study of a DG interconnection, because DG penetration greater than the threshold levels could adversely impact the transmission and distribution system. For instance, when the penetration of DG for a distribution feeder exceeds 10% of the peak annual KVA load of the feeder, the Rule 14.H. interconnection standards provide that a technical study be commenced. Also refer to PUC-IR-14. Other potential situations where DG could have adverse effects on the system are outlined in HECO's Rule 14.H., Sheet No. 34B-7, which include additional study if the short circuit contribution ratio of the DG facility is greater than 5% or if the DG facility is interconnecting onto the utility's network systems. HECO Companies' Response to PUC-IR-13.

c. T&D Planning Criteria

The HECO Companies have transmission and distribution planning criteria, which are used to establish guidelines for planning reliable transmission and distribution systems for HECO, HELCO and MECO. HECO T-4 at 3-4.

Transmission Planning Criteria for HECO, HELCO and MECO are shown in HECO-401, HECO-402, and HECO-403 respectively. Distribution Planning Criteria for HECO, HELCO and MECO are shown in HECO-404, HECO-405 and HECO-406 respectively. HECO T-4 at 4-5.

The transmission planning process is applied to (1) the HECO 138 kV, (2) the HELCO 69 kV and 34.5 kV sub-transmission system and (3) the MECO 69 kV and 23 kV sub-transmission system. The distribution planning process is applied on the 12 kV voltage level and below for HECO, HELCO and MECO. HECO's 25 kV distribution system and the 46 kV sub-transmission system are also included in the distribution planning process.[26] The computer models and load flow simulations used in transmission system planned were identified in HECO T-4. HECO T-4 at 4-5.

The Transmission Planning Criteria provide minimum guidelines for planning the transmission system. For instance, voltages exceeding acceptable tolerance levels or current flows exceeding the current carrying capacity of transmission lines are criteria violations. Criteria violations can be triggered due to load growth such as the Koolau/Pukele line overload described in the East Oahu Transmission Project ("EOTP"), Docket No. 03-0417, HECO T-4 at 7. In contrast, reliability concerns are identified by analyzing the reliability of customer's electric service and may exist even if in the absence of criteria violations. An example of a reliability concern is the reliability of the Pukele and Downtown area substations on the HECO system as described in EOTP, Docket No. 03-0417, HECO T-4 at 33-48. HECO T-4 at 6.

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[26] The Company's T&D planning processes were presented at the April 23, 2004 IRP Advisory Group Technical Committee meeting. An outline of the transmission planning process and the distribution planning process for the HECO Companies was included in HECO-407 and HECO-408, respectively. HECO T-4 at 5.

d. DG/CHP Is Incorporated Into T&D Planning Studies

Quantifying and assessing the value of DG to resolve T&D criteria violations and/or reliability concerns requires detailed planning studies that incorporate a variety of possible options, including load reduction options such as DG, CHP and/or DSM. The HECO Companies' T&D planning process, which is conducted in a manner consistent with the IRP planning process, incorporates both T&D capacity options. HECO Companies' Response to PUC-IR-12.

DG/CHP is considered in the transmission planning process on a system wide basis and included in the Company's Sales and Peak Forecast, which is the basis for calculating a load growth rate. This load growth rate determines the amount of load that the system is expected to serve at various locations of the system and this is input into a load flow model. By performing load flows using computer simulations, the HECO Companies identify transmission planning criteria violations and reliability concerns. The Companies also examine possible solutions, which include increasing transmission capacity, reduction of load through the installation of DG, CHP or DSM (above what is forecasted on a system wide basis), or a combination of both. Load flows are replicated to determine the viability of a solution. This process was followed for the transmission planning studies filed in Docket No. 03-0417 (East Oahu Transmission Project), Exhibit 6. This process was also followed in the draft 7200/7300 Line Overload Study on the HELCO system, which was attached in response to CA-SOP-IR-15. In addition, the 10 Year Transmission Study (2004-2013) for the MECO system was completed and finalized. See Executive Summary attached to HECO Companies' Response to PUC-IR-9. HECO Companies' Response to PUC-IR-12.

e. Distribution Planning Process

Most of the analysis in distribution planning is conducted looking at historical loads by taking actual load demand readings from distribution substation transformers and readings from each individual distribution line. In some cases, the computer load flow simulation model is used to model select areas of the distribution system. HECO T-4 at 7.

Long term forecasts are not created for the distribution planning process because (1) distribution load forecasting is geographically dependent and therefore very dynamic, (2) growth rates between lines are highly variable, (3) distribution load forecasting is highly dependent upon customer plans, (for example, a new hotel can double the load on a distribution line) and (4) useful forecasting for distribution system rarely exceeds five years. Thus, short-term forecasts are used in the distribution planning process to determine power and current flows through the sub-transmission and distribution systems, voltages on the system, and transformer loadings. Distribution planning criteria and reliability concerns are identified. HECO T-4 at 7.

f. Using DG to Address T&D Planning Criteria Violations

Two types of options can be considered and evaluated to resolve T&D planning criteria violations and reliability concerns for the T&D systems. These options are (1) the installation or modification of T&D facilities, and (2) load reduction options. HECO T-4 at 7.

In general, the HECO Companies consider many types of T&D options. These include:

(1) increasing the capacity of the T&D system through the addition of new lines, reconductoring existing lines, re-tensioning existing lines (as discussed in EOTP, Docket No. 03-0417, HECO T-4, pages 76-78), or re-rating existing lines (through techniques such as dynamic line rating as discussed in EOTP, Docket No. 03 0417, HECO T-4, pages 75-76),

(2) reconfiguring distribution or sub transmission lines, which shift loads and change the current flows on the transmission system or provide redundancy on the distribution system (as discussed in EOTP, Docket No. 03-0417, pages 59-62),

(3) adding VAR sources such as capacitors on the transmission system (refer to Docket No. 03-0388, Kailua Capacitors) and/or

(4) adding additional transformer capacity on the sub transmission and/or distribution transformers. HECO T-4 at 7-8.

Non-T&D options such as implementing sustained DSM programs and installing DG facilities have been considered in past T&D analyses and increased evaluation of non-T&D alternatives is being included in more recent T&D analyses. Non-T&D options related to DG facilities have included the evaluation of diesel generators at the Company's substations, customer-sited, utility-owned CHP programs and utilizing emergency standby generation. HECO T-4 at 8.

DG facilities have the potential to reduce the load served by the T&D system either on a continuous basis or during contingency situations. Reducing the load served by the T&D system will reduce current flow and could defer the need to install transmission facilities to address the criteria violations. The installation of a customer-sited CHP system, which is used continuously is an example of where the load reduction may be considered on a continuous basis (although when planning for the system) maintenance of the unit(s) must be considered. Installing DG at substations, which is permitted to operate under emergency conditions, is an example of DG used during contingency situations. The ability to operate under emergency conditions requires a contingency situation to occur before the DG unit can be utilized and the run hour times for these emergency units are restricted. HECO T-4 at 8.

g. Diesel Generation at T&D Substations

The HECO Companies' planning studies have considered the installation of diesel generators at T&D substations. For example, on the MECO system, the installation of diesel generators was considered for Hana Substation. HECO T-4 at 9.

A single radial transmission line connected the Hana Substation is connected to the utility grid. Prior to the installation of distributed generators, the area was at risk of power interruptions whenever a problem arose or maintenance was performed on the line. The installation of diesel generators provided an attractive alternative to installing additional transmission facilities. Two diesel engine generators from the Lanai City Power Plant were relocated to Hana Substation No. 41 to provide standby electric service to the Hana community during planned service outages resulting from the maintenance or unplanned power outages of the single transmission line to Hana. HECO T-4 at 9.h

MECO considered numerous factors in its decision to relocate the diesel engine generator to Hana, including the age of the single transmission line, the terrain surrounding the transmission line, the effect of an outage on the customer, and the cost for resolving the reliability issue were considered prior to installation. Hana's single transmission line was over 35 years old and was shown to be a weakness in the Hana area system reliability. In addition, due to its location, the need to repair and maintain the transmission line presented additional difficulties, and resulted in unscheduled and scheduled outages affecting the Hana Substation, which in turn caused service interruptions to Hana customers. MECO considered other options, including the installation of a 35-mile redundant single circuit on steel poles from Kanaha substation that was estimated to cost over $20 million, or relocating two existing Lanai City Power Plant diesel engine generators to Hana. The actual cost to relocate the two generators to Hana was $1.24 million. Relocation of the diesel generators provided a relatively low cost

option, because the diesel engine generators were scheduled to be retired in any event and other issues, such as the fuel supply and locating a suitable area in the substation, were addressed. HECO T-4 at 10.

There are practical considerations, however, which limit the ability to install diesel generators on a targeted basis to defer specific T&D projects, and DG has not been determined to be a cost-effective or feasible alternative in other analyses.[27]

h. Utility's Ability To Target DG/CHP In Areas With Criteria Violations/Reliability Concerns

Targeting CHP installations in areas where there are identified criteria violations or reliability concerns requires the evaluation of additional CHP installations in the service areas beyond the level expected to result from current programs and efforts. In concept, evaluation of DG and CHP installations can be analyzed on a case-by-case basis, however, there are a number of issues to consider including: (1) DG diversity issues and T&D peak load planning, (2) timing of DG and CHP installations, which may not coincide with the Company's requirements, (3) the customer's commitment to the operation and maintenance of DG and CHP units, (4) reliance on customers, who will only install DG and/or CHP only if it is cost-effective, and (5) other practical considerations. HECO T-4 at 13-14.

Creating DG Diversity

The HECO Companies generally plan based on the peak load forecast under various contingency conditions. Depending on the situation being analyzed, day or evening peaks are considered. Therefore, it cannot simply be concluded that the load-carrying requirements on the line feeding the customer with DG facilities would be reduced. The extent of the installation of

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[27] DG was considered in the analyses for the East Oahu Transmission Project ("EOTP"), Docket No. 03-0417 and for the 7200/7300 HELCO Line Overload Study. Installation of diesel generation in

multiple DG units is dependant on factors such as the relative sizes of the units, the reliability characteristics (i.e., forced outage rates) of the units and the utility's ability to coordinate scheduled maintenance or require that scheduled maintenance take place during off-peak periods (as a result of contractual agreements with enforcement provisions). The load-carrying requirements would not be reduced to the extent that the utility still has to plan to carry the entire load when the DG is off-line. HECO T-4 at 14.

Specific analysis to determine the number and/or size of DG facilities that would be required to create diversity has not been conducted. However, diversity can be illustrated conceptually. For example, if there is a single DG on a circuit to serve a particular load, times will arise when DG will be unavailable due to a planned or forced outage. In this case, diversity will exist and the grid must provide backup to the DG, in which case the need for firm system capacity would not be deferred. If there are multiple DG units on that circuit, there may still be times when the combined output of the DG units may be zero due to a combination of planned and forced outages. However, the probability of the combined output being zero is reduced. That probability will be a function of the number and sizes DG units, their planned outage requirements, and their forced outage rates. HECO T-4 at 14-15.

Timing

The timing of DG on customer sites and CHP facilities may not necessarily coincide with the Company's need to resolve T&D criteria violations or reliability concerns. Unlike DG installations at the Company's substations, where the installation, operation and maintenance of the units can be controlled more than an on-site DG or CHP facility, the installation of on-site DG controlled by the customer and installation of CHP cannot be fully controlled by the utility.

North Kohala was also considered as part of HELCO's March 1996 Contingency Plan Update, Docket No. 96-0029. HECO T-4 at 10-13; see HECO Companies' Response to PUC-IR-12.

Customers may have other criteria in mind when they decide whether to install DG on-site or CHP. For instance, most commercial customers will be drawn to implement DG or CHP during periods when the existing building of a business is expanding, with the installation of a new facility, or at a point in time where large pieces of equipment such as the air-conditioning system require upgrades or replacement. The time frame for the customer to implement DG and/or CHP facilities may not necessarily coincide with the utilities need to resolve T&D criteria violations or reliability concerns. HECO T-4 at 15.

Customer Commitment

A customer's commitment to the operation and maintenance of DG and CHP units is an important consideration. Contractual agreements are not in place between the utility and the third-party CHP facility. As a result, a customer's commitment towards operating and maintaining a reliable facility is uncertain. For instance, a CHP facility could be shut-down for maintenance during peak periods when the facility is needed most to address T&D concerns. HECO T-4 at 16.

The HECO Companies will have more control over a utility-owned CHP facility than over a third-party CHP facility. The Companies would have access to data which can determine how the facility will be operated. The utility is responsible for the maintenance of the facility, and can maintain the facility based on utility standards to increase reliability rather than only cost considerations. These may be the case for a third-party CHP facility. However, with a utility-controlled facility, maintenance of many units can be coordinated to provide diversity. HECO T-4 at 16; see Tr. (12/08/04) at 134-138 (Seu).

Cost-Effectiveness

Installing targeted DG facilities specifically to address T&D criteria violations or reliability concerns, even where possibly feasible, may not be cost-effective. For instance, the

EOTP analysis showed that costs to install DG and CHP to address only the Koolau/Pukele line overload situation exceeded the cost of installing transmission system upgrades on the 46 kV system. Although the relocation of the Lanai City diesel generators was a cost-effective solution, the diesel generators being used were already scheduled to be retired, which contributed the relatively low relocation costs. Other analyses on the HECO and MECO system have considered new generation installations to mitigate T&D problems. HECO T-4 at 16.

Other Practical Issues/Considerations

Practical considerations may limit the ability of DG to be used on a targeted basis to defer specific T&D projects. Practical issues include the availability of land and often inadequacy of land sites on customer or residential property in the installation area where DG is required to mitigate the identified T&D problem, the development of fuel supply and maintenance resources, interconnection requirements, permitting issues, and the ability to use existing "emergency" back-up generators for the purpose of resolving T&D problems. HECO T-4 at 11, 17; HECO Companies' Response to PUC-IR-12.

Use Of Emergency Generators

The concept of operating onsite emergency generators as a "virtual power plant" was suggested by COM. Onsite emergency generators operate very few hours per year and, therefore, may be able to address transmission concerns only during contingency situations. However, backup or emergency generators are normally installed by large customers to provide electrical power to their essential services (such as emergency lighting and critical electronic equipment) in the event that power from the utility is unavailable. It is likely that when a system emergency occurs and the utilities need backup power from such "virtual" power plants, simultaneously, large customers would be likewise affected by the same system emergency and would be calling upon their emergency generators to provide power. In such cases, although

there may be an increase in reliability to the individual customer with the onsite emergency generator, the "virtual" power plants would not be able to provide backup power to the grid and there would be no increase in reliability to the T&D system. HECO T-4 at 17.

2. Market Impacts

Depending upon who installs, owns and operates the DG system, the impacts on the Hawaii electric market are markedly different. If a third-party or a customer installs DG, the load to be served by the utility is reduced and the utility loses the portion of the rate normally charged to the customer to cover fixed costs. When this occurs, those costs must be borne by other ratepayers when rates are next adjusted at the next rate case. In the interim, the utility shareholders bear the loss. If the utility owns and operates the DG system, the loss of fixed costs is substantially reduced and the overall program costs and payments can be structured so that all parties (the utility, the customer, and other non-participating ratepayers) are better off by having the project completed. HECO T-1 at 22.

a. Utility's Assessment Of CHP Market

In early 2003, each of the HECO Companies assessed the CHP market potential in their respective territories for purposes of a potential CHP Program. Each company began with a list of their largest customers (for Oahu, this was all customers with a demand greater than 400 kW). The Companies' initial assessment of the technology indicated that projects below approximately 200 to 250 KW would generally not be economical. Based upon their knowledge of the customer's operations, the Companies determined which of these large customers had a potential CHP application. Key determinants were the size of the customer's air conditioning load, the hot water or steam requirements of the customer, and the age of the customer's central plant. Once the reduced list was established, the Companies assigned a probability to each customer to indicate the Companies' opinion of the likelihood that a specific customer would be interested in

a CHP program, based in part upon information available from the customer such as the approximate age of the customer's central plant. The Companies then assigned a tentative date as to when CHP would be most economically sound. This process yielded a likely number of kilowatts of CHP by year for each company. HECO T-1 at 23.

The Companies reviewed the nature of the high probability customers to determine how a generic CHP system might be defined for analytical purposes. Rather than attempt to model each customer or a wide variety of customers, it was decided that it would be more practical to define a generic unit from which per kilowatt or per kilowatt-hour values could be derived for analytical purposes. Once the generic unit was defined, an analysis was done to define the total impact of the CHP program on the utility systems. The use of an absorption chiller displaces an electric driven chiller thereby reducing electrical load, and increasing the effective efficiency of the CHP system. HECO T-1 at 23-24.

Finally, the Companies' determined the impact of the Companies' entry into the market. Based upon direct discussions with customers, it was determined that utility participation in the market would result in more CHP being developed overall. Third parties were expected to continue to participate in the market, however. This resulted in the CHP market forecast that ultimately was filed in the Companies CHP Program application in Docket No. 03-0366. HECO T-1 at 24.

HECO updated the CHP market forecast within its HECO's IRP-3 process. During the IRP process, the numbers from the CHP Program application forecast were increased. This reflected new knowledge regarding the potential for several large CHP system projects, delays in starting the CHP Program, and the sentiment of the IRP CHP Technical Committee that HECO's

CHP Program application forecast was too conservative. This HECO IRP CHP forecast was provided as HECO-104. HECO T-1 at 24.

HECO projected a higher IRP forecast because numbers representing several potential larger projects were added in years 2005 to 2009. These projects were for construction of new facilities or for expansion of existing facilities of several large customers. These projects were not included in the CHP Program application forecast since that forecast focused on retrofits of existing installations. In addition, 200 kW in additional CHP was added to each year beyond 2010, to reflect the sentiment of the IRP CHP Technical Committee. HECO T-1 at 24.

As indicated earlier, the market for CHP systems is driven by CHP customer needs, and the extent to which CHP systems can satisfy those needs and produce cost savings. As a result, forecasts of the timing of CHP installations and the amount of CHP to be installed will continue to change. In addition, the delay in authorization for the utilities to install CHP systems has substantially reduced the rate at which CHP systems are being installed. While customers are free to contract with third-parties for the installation of such systems pending the outcome of this proceeding, they generally are not doing so since the utility-ownership system is the preferred option for many potential CHP customers.

Larger Market With the HECO Companies' Direct Participation

The overall CHP market will be larger only if the HECO Companies are allowed to offer utility-owned and operated CHP services to customers, than if the Companies are permitted to merely facilitate use of the CHP technology. HECO RT-1 at 18-19.

Direct utility participation in the market, meaning utility-owned CHP, is expected to result in greater CHP development overall. HECO RT-1 at 17. The Companies would not simply be displacing CHP system and/or DG installations that might have been installed by

non-utility vendors. Rather, the HECO Companies' participation will increase the number of CHP system installations. Responses to COM-HECO-DT-IR-5; HREA-HECO-IR-7.

The primary basis for the Companies' assessment of a larger CHP market with the Companies' participation is the strong customer support and demand for the Companies' CHP Program. The most critical factor is the sentiment from many facility owners that they do not want to own, operate or maintain CHP systems. For this reason, the HECO Companies' unique model of utility-owned, operated and maintained CHP systems is appealing. HECO RT-1 at 17-18.

Equipment vendors also have supported utility direct participation in DG market. For example, Hess stated that, "Distributed generation should be owned and operated by both regulated electric utility companies and private companies to provide customers with the most options." Hess DT at 2 (Gregg). Further, Hess recognized the importance of customer choice in allowing the electric utilities to directly participate and the resulting positive effects on customers: "The regulated electric utility companies and private companies offer customers distinct options in regards to ownership, installation, maintenance, and rates. These distinct options will permit customers to select the provider that will best meet their needs for reliable power at a fair cost." Hess DT at 2 (Gregg).

B. ISSUE #5: WHAT ARE THE IMPACTS OF DISTRIBUTED GENERATION ON POWER QUALITY AND RELIABILITY?

1. DG Impact On Power Quality Is Complex

The impact of DG facilities on T&D power quality can be very complex and can require detailed studies on a case-by-case basis.

The impact of DG located at customer facilities is dependent on location specific issues such as configuration of the distribution system (e.g., radial vs. network), length of distribution

lines, penetration of distributed generation on the primary circuit and the back up circuit, reliability and redundancy of customer systems, type of generator (e.g., synchronous or induction) grounding of transformers and other equipment, and short circuit characteristics of the distribution circuit. HECO T-4 at 25.

a. DG May Cause Voltage Regulation Issues

The DG interconnections can cause an increased risk of voltage regulations problems, adverse interactions with the utility's protection system and unintended islanding as the penetration DG capacity increases on a utility distribution feeder. Tariff Rule 14.H, which establishes how the interconnection of a DG system is to be handled, requires additional technical study to examine the risk of these problems when the aggregate generating capacity per distribution feeder exceeds 10% of the peak annual KVA load of the feeder. HECO T-4 at 25-26.

According to a February 2002 Electric Power Research Institute ("EPRI") Technical Update titled "Integrating Distributed Generation Into the Electric Distribution System," ("February 2002 EPRI Technical Update") DG can create unusually high or unusually low voltages depending on the size of the DG and the distribution circuit characteristics at the installation location. When real power is injected into the power system, the voltage at the point of injection will increase, in proportion to the size of the DG (either individual or in aggregate). Conversely, if a DG point of interconnection is near a substation voltage regulator, low voltages could occur at the end of a long radial feeder. Therefore, additional technical studies may be required in order to determine the impact of DG with respect to voltage regulation. Low or high voltages in the local area can affect customer equipment connected to the distribution line experiencing the low or high voltages. HECO T-4 at 26.

Preliminary analysis on the HELCO system shows that the use of synchronous DG/CHP generation can help with voltage recovery after a line fault due to the ability of such generation to "field force", and could improve voltages in localized areas. If synchronous DG/CHP generating units are unable to ride through low voltage situations, however, the DG/CHP units could trip off. This would result in slower voltage recovery after a voltage collapse and the possibility of interrupting customers due to underfrequency load shedding on the HELCO and MECO utility grids, because these grids operate with quick-start diesels (instead of carrying spinning reserve such as HECO does). In addition, the use of induction DG/CHP generation slows voltage recovery due to drawing increased reactive power during voltage collapse conditions.

b. <u>DG May Adversely Affect Utility's Protection Schemes</u>

The February 2002 EPRI Technical Update also explains that if not done properly, installation of DG could result in unintended tripping of protective relaying devices. To prevent this possibility, DG must follow safe and reliable interconnection and operating practices, including coordination with the circuit breaker settings, recloser practices and fusing of the utility's distribution system. The DG facility should be available to operate during normal utility system conditions and safely disconnect and reconnect from the utility system when the need arises such as during contingencies. When the utility system is under maintenance, the DG system must either disconnect from the utility system and/or be isolated from the grid to insure the safely of utility personnel performing the work on the de-energized utility system. In addition, the preferred specification for relaying should be what is referred to as a "utility grade" relay which meets ANSI/IEE surge withstand capabilities, has high accuracy in pickup and time settings and has a testable interface. The definition of utility grade was defined on Sheet No. 34B-5 of Rule 14.H. HECO T-4 at 26-27.

c. DG May Impact Reliability

DG can benefit the electric T&D system in several ways. Depending on where it is installed, DG can affect the reliability of a single customer's electric service or otherwise affect the T&D system. DG can benefit the reliability of a single customer's electric service if it is able to operate while connected to the utility power system and isolated from the utility, which could occur if there was a T&D outage. Installing back-up emergency diesel generators, capable of supporting critical portions of operations at customer sites, may also provide reliability improvement to a single customer's electric service. HECO T-4 at 2, 9.

Under certain circumstances, DG may also improve the reliability of localized areas of the T&D system when installed at targeted utility substations. This was addressed under Issue #5, in Section III.B of the Opening Brief.

In other situations, DG may also adversely impact the reliability of the customer's electrical service and/or the utility's system. Initially, installations of small-scale DG units at customers' sites for purposes other than emergency backup were often problematic for both the customer and the utility. From the customers' standpoint, there were performance problems with the units, with the fuel for the units and with the maintenances of the units. In fact, a number of the initial units are no longer operable and/or have been replaced, such as the units at the University of Nations and at the Hualalei Regency. From the T&D system standpoint, unexpected outages that could be caused by poor unit performance or maintenance practices can adversely impact local voltage and frequency control. HECO T-4 at 2.

C. ISSUE #6: WHAT UTILITY COSTS CAN BE AVOIDED BY DISTRIBUTED GENERATION?

1. Avoided Costs

The avoided costs relevant to this docket are the incremental or additional costs to the utility of electric energy, firm capacity or both which the utility would avoid as a result of the installation of DG.

In general, distributed generation has the potential to defer or avoid certain utility costs, including (1) new central station generating capacity and fixed operation and maintenance ("O&M") costs – avoided capacity costs; (2) utility central station generation fuel and variable O&M costs to the extent they displace utility generated energy – avoided energy costs; and (3) new transmission and distribution ("T&D") capacity, depending on the specific nature of an area's T&D system and the ability to site DG there – avoided T&D costs; and (4) avoided T&D line losses. See HECO T-4 at 4-18.

a. Avoided Capacity Costs

Avoided generation capital costs are those capital costs associated with the installation of firm utility central station generating capacity that can be avoided by deferring the installation date of that firm capacity. Fixed O&M costs are those operation and maintenance costs that are incurred by a generating facility regardless of whether or not the facility operates or produces energy. These costs include items such as staffing, insurance, general maintenance of the facility and land leases. Avoided fixed O&M costs are those fixed O&M costs that can be avoided by deferring the installation date of a firm generating facility. Firm DG capacity added to the system can defer the need for new firm utility central station generating capacity and can result in avoided generation capitol costs and fixed O&M costs. HECO T-3 at 4-6; see HECO-304.

Firm capacity is that generating capacity that can be called upon by the utility to safely and reliably provide energy in defined amounts at scheduled times. In many instances, DG can be considered firm capacity. In order for a single DG installation to be considered firm capacity,

the utility should be able to control the operations of and maintenance quality of the installation. The DG should also have a reliable fuel supply and an adequate amount of fuel storage. The DG must provide a compatible monitoring and control system to allow the utility to dispatch the DG installation to allow for responsiveness to utility system conditions. HECO T-3 at 2-3.

If DG can be considered firm capacity, it can defer the need for new central station generating capacity If the DG can be considered firm capacity and the DG facility (or multiple DG facilities in the aggregate) is sufficiently large, it can defer the need for new central station generating capacity. HECO T-3 at 3.

b. Avoided Energy Costs

Avoided generation fuel costs are those utility central station fuel costs that would not be incurred as a result of the generation of electricity by some other source. Variable O&M costs are those non-fuel operation and maintenance costs that are incurred by a generating facility that are a function of the amount of energy produced or the number of hours a generating unit operates. Energy produced by DGs can displace the energy that would otherwise be produced by utility central station generating units or can result in reduced operating hours for the utility central station generating units. When this occurs, utility central station fuel costs and variable O&M costs are avoided. HECO T-3 at 5-6.

c. Avoided T&D Capital Costs

Avoided transmission capital costs are those capital costs associated with the installation of transmission facilities that can be avoided by deferring the installation date of proposed transmission facilities. Firm DG capacity added to the system can defer the need for new firm utility central station generating capacity. This can defer the need to install transmission facilities associated with the installation of new firm utility central station generating capacity and can result in avoided transmission capital costs. Multiple DG unit installations in one area

may reduce the load demand in a geographic area or may be able to provide new generation to match the load growth rate of an area. Reducing the load demand in an area or providing new generation to match the load growth rate of an area may be able to defer the proposed transmission facilities required to serve the increasing load demand. HECO T-4 at 18-20.

In concept, avoided distribution capital costs are similar to avoided transmission capital costs and include capital costs associated with the installation of distribution facilities that can be avoided by deferring the installation date of the proposed distribution facilities or eliminating the need to install distribution facilities. HECO T-4 at 22-23.

Additionally, in concept, if DG facilities are installed to match new customer loads or customer increases in power consumption then T&D facilities will not be required because the grid will not see the added load. In this instance, the entire cost to build the T&D facilities to serve the customer can be avoided and are classified as a replacement avoided costs. If, for instance, DG facilities are installed in an effort to match new customer load and the growth rate in the area suddenly increases beyond the capacity of the DG installations, it may be necessary to install T&D facilities to account for the differences. The DG installations in this instance served to defer T&D upgrades. Therefore, where a system is planned in this manner, it is important to recognize that there may be some risks involved. The forecasts for the areas must be accurate in order to avoid mismatches between DG and load demand, because installing T&D facilities to resolve the mismatches would take time to implement. HECO T-4 at 23.

Most DG projects will <u>not</u> result in avoided distribution capital costs, because DG projects are driven by customer choice. DG projects may or may not be a part of the system where distribution upgrades are required. HECO T-4 at 23-24.

d. Avoided T&D Line Losses

DG units can be connected to the distribution system and serve the local load connected to the DG facility. This reduces the power output needed from central station generation and, therefore, reduces the amount of power flowing through the transmission line. However, it is important to note that the DG facility must be installed and running in order to realize a reduction in power flow through the transmission system. HECO T-4 at 21.

D. ISSUE #7: WHAT ARE THE EXTERNALITIES COSTS AND BENEFITS OF DISTRIBUTED GENERATION?

The externality impacts associated with DG generally are the same impacts associated with any form of generation. Distributed generation brings both positive and negative externality impacts, as described below. Many of the negative externalities, however, can be mitigated by proper design and siting. HECO T-1 at 35.

1. Positive Externalities Impacts/Externality Benefits

a. Ability To Meet Special Needs Of User

The ability of DG to meet the specific needs of an energy user provides a positive externality impact of DG. Distributed generation, particularly that which is installed at an end-user's site, can be tailored to meet a user's specialized energy needs. For example, distributed generation can provide backup or premium power to meet reliability or power quality needs of a facility. In another instance, a facility with sufficient thermal loads may be able to utilize a combined heat and power system to achieve greater energy efficiency and energy savings. The flexibility and variety of distributed generation systems and applications is a key benefit. HECO T-1 at 35.

b. **Fuel Efficiency/Avoidance of Fossil Fuels**

Distributed generation from renewable energy directly avoids the burning of fossil fuels. In addition, certain types of distributed generation that use fossil fuels can be highly efficient, such as CHP systems, as featured in the HECO Companies' proposed program. The thermal efficiency of fuel usage in a CHP system typically ranges from 85% to 90%, in contrast to 35% to 40% for a conventional central station generating unit. Moreover, distributed generation of all types can reduce transmission line losses, which provides additional efficiency improvements and benefits. HECO T-1 at 35-36.

c. **Scale**

Because DG is installed at much smaller scale than central station generation, DG provides an enhanced ability to switch to new technologies due to lower incremental costs. Therefore, the use of DG avoids the necessity for a single, large investment. HECO T-1 at 36.

2. **Negative Externalities/External Costs**

Negative externalities of distributed generation are chiefly in the area of environmental externalities, as described below:

a. **Air Emissions**

Fossil-fuel based distributed generation, such as reciprocating engines, combustion turbines, and microturbines, result in associated emissions, including NOx, SO2, CO, and CO2. The Hawaii Department of Health ("DOH") regulates emissions via its noncovered source and covered source air permitting rules. One identified concern is that DG is located closer to the locations of load demand than is central station power generation, and there may be greater likelihood of exposure to the populace to DG emissions. Nonetheless, this concern is mitigated by the fact that DG installations and resulting emissions appear on a much smaller scale than emissions from central station power plants. In addition, emissions impacts from DG can be

mitigated with appropriate emissions controls, good engineering practice design of exhaust ducts, and operational measures to assure efficient combustion of fuel. HECO T-1 at 36.

b. Noise

Distributed generation that employs moving machinery, such as reciprocating engines, combustion turbines, microturbines, and wind turbines, inherently emits noise. Increased sensitivity to noise impacts resulting from DG may occur where sited at the distribution level of a power grid in residential and commercial areas, than for a central station power plant located in an industrial area. Fairly strict noise standards for residential areas are established in Hawaii. These standards are regulated and enforced by the DOH. HECO T-1 at 36-37.

c. Visual Impact

Distributed generation may bring both positive and negative visual impacts. Visual impacts can be positive from the perspective that if transmission infrastructure can be deferred or obviated, the visual impacts of that infrastructure can be avoided. Yet, impacts can be negative if the distributed generation installation itself is visually obtrusive, such as may be the case with wind turbines, photovoltaic arrays, or exhaust stacks. HECO T-1 at 37.

E. ISSUE #8: WHAT IS THE POTENTIAL FOR DISTRIBUTED GENERATION TO REDUCE THE USE OF FOSSIL FUELS?

DG from renewable sources of energy directly avoids the burning of fossil fuels, reducing overall fossil fuel consumption. Wind turbines and photovoltaic systems are the most likely form of renewable distributed generation.

In addition, certain types of distributed generation that use fossil fuel can be highly efficient, such as CHP systems. As stated above, the thermal efficiency of fuel usage in a combined heat and power system typically ranges from 85% to 90%, as compared to 35% to 40% for a conventional central station generating unit. Thus, a CHP system requires roughly

half as much fuel as a conventional generation unit. Further, distributed generation of all types can reduce transmission line losses. This provides additional efficiency improvements and reduction in the use of fossil fuels. HECO T-3 at 20.

As a result, CHP systems, while using fossil fuel, can result in meeting electrical and thermal energy needs by using less oil. Specifically, the value of CHP systems is derived from the recovery of waste heat that would otherwise be wasted. The use of this waste heat makes it a "reusable" energy source that displaces fossil fuels. The Hawaii Legislature recognized the benefits of saving energy and therefore expanded the definition of renewable energy in the RPS law to include the energy saved from efficient generation technologies such as CHP systems, as well as district cooling, ice storage and energy conservation measures. HECO T-2 at 24.

The amount of fossil fuel reduction that might be achieved in Hawaii through the use of distributed generation depends upon the type of distributed generation technology, site-specific factors, and the baseline state of central station generation to which DG is being compared. The type of distributed generation technology employed will depend on its technical and economic feasibility, and ability to be integrated into the grid or a customer's system. HECO T-3 at 20-21.

For example, the amount of fossil fuel that can be avoided by CHP systems will depend on the usage of the individual units and their individual efficiencies. The fuel efficiency of the CHP systems will be compared to that of the central station power plants in existence at that time, which would otherwise have supplied the energy. HECO T-3 at 21.

IV. IMPLEMENTATION ISSUES

A. ISSUE #9: WHAT MUST BE CONSIDERED TO ALLOW A DISTRIBUTED GENERATING FACILITY TO INTERCONNECT WITH THE ELECTRIC UTILITY'S GRID?

1. Tariff Rule 14.H

a. Background

For a distributed generating facility to interconnect with the HECO Companies' grids, it must comply with their respective Rule 14.H, Interconnection of Distributed Generating Facilities Operating in Parallel with the company's Electric System. All distributed generating facilities, including any proposed Company-owned and operated CHP systems, must comply with Rule 14.H, and will be subject to the same technical review and study process. Preliminary SOP at 28.

On January 15, 2002, the HECO Companies filed their proposed modification to their respective Rule 14, adding Paragraph H., to establish interconnection standards and to require an interconnection agreement for distributed generating facilities operating in parallel with their respective electric system, Transmittal No. 02-01, 02-02H and 02-01M, respectively. By Order No. 19231, filed March 4, 2002, the Commission consolidated the three transmittals, and opened Docket No. 02-0051. On March 21, 2002 and April 10, 2002, the Companies filed responses to the Consumer Advocate's first and second submission of information requests, respectively. By a joint letter filed September 23, 2002, the Companies and Consumer Advocate jointly submitted for Commission review and approval their agreed upon proposed modification to Rule 14 to establish interconnection standards and to require an interconnection agreement or distributed generating facilities operating in parallel with the Companies' respective electric system. In Decision and Order No. 19773 ("D&O 19773"), filed November 15, 2002, Docket No. 02-0051, the Commission conditionally approved the Companies' opposed modification to their respective

Rule 14, and the Commission made several observations with respect to the proposed modification to Rule 14.

In D&O 19773, the purpose of and the key section of these standards were summarized:

> Appendix I sets forth comprehensive interconnection standards and technical requirements that are intended to facilitate the interconnection and parallel operation of a customer's distributed generating facility with the utility's electrical system. The underlying purposes of the technical interconnection requirements are to: (1) maintain safety, reliability, and power quality and restoration; (2) protect the utility's and customer's equipment and facilities; and (3) advance the operating efficiencies of the utility's electrical system.
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> In general, the interconnection standards and technical requirements consist of: (1) a definitions section; (2) general interconnection guidelines; (3) design requirements; (4) operating requirements; (5) technology specific requirements; and (7) schematic diagrams illustrating "typical equipment and protective device requirements for large synchronous, induction and inverter generators".

By a joint letter filed February 19, 2003, the HECO Companies and the CA jointly submitted for Commission review and approval their agreed upon revisions to the proposed modification to Rule 14 that resulted from their review and consideration of the Commissions' observations that were included in Decision and Order No. 19773, and certain other revisions proposed by the Companies. On March 6, 2003, the Commission issued Decision and Order No. 20056, Docket No. 02-0051, which provided final approval of the Companies' proposed modification to Rule 14.

On March 14, 2003, the Companies filed their respective Rule 14.H tariff sheets, which became effective March 21, 2003. Also included in the Rule 14.H tariff sheets are 1) Appendix I, Distributed Generating Facility Interconnection Standards Technical Requirements, 2) Appendix II, Standard Interconnection Agreement, and 3) Appendix III, Interconnection Process Overview. By Order No. 20220, filed May 30, 2003, the Commission approved the Companies' proposed modification to the Standard Interconnection Agreement, Appendix II, for

self-insurance for governmental entities. On June 4, 2003, the Companies filed their respective revised Rule 14.H tariff sheets for the Standard Interconnection Agreement, Appendix II, which were effective June 6, 2003. Preliminary SOP at 28-29.

b. Impacts of DG On The Utility System

Customer-sited generation operated in parallel with the utility grid differs from off-grid, customer-sited generation, because the facility operated in parallel with the grid receives back-up power from the utility. Therefore, the customer remains electrically connected to the Company's grid. Off-grid, customer-sited generation is not electrically connected to the Company's grid and the customer does not require back-up power from the Company. Rule 14.H outlines the interconnection agreement procedures and the technical review process for generators operating in parallel with the Company's grid and provides interconnection requirement standards for DG facilities that do not export power to the utility.[28] HECO T-4 at 28-29.

Exporting Power To Grid

The impact of DG facilities located at customer sites and operations in parallel with the grid is dependent upon location-specific issues described in Section IV.A.1 of this Opening Brief. Therefore, the power quality and reliability impact of a specific distributed generator will depend upon an individual site and should be evaluated on a case-by-case basis. HECO T-4 at 29.

One of the impact issues established by the interconnection standards is the potential for "islanding". Rule 14.H defines "islanding" as a condition in which one or more generating facilities deliver power to a utility customer or customers using a portion of the utility's

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[28] Even if a customer's facility could meet the standard interconnection requirements set forth in Rule 14.H, additional technical study would be required for facilities that export power to the HECO Companies' grids. As stated earlier, Rule 14.H was designed to provide interconnection standards

distribution system that is electrically isolated from the remainder of the utility's distribution system. According to Rule 14.H, unintended islanding may occur following an unanticipated loss of a portion of the utility distribution system. Dangers associated with unintended islanding may include public and utility personnel safety, prevention of possible damage to customer equipment. HECO T-4 at 27-28.

c. **Interconnection Costs**

Interconnection costs for DG will vary based on factors such as project size and location. Rule 14.H outlines the interconnection requirements which would have an associated cost. For instance, the DG facility may need to install a grounding scheme, isolation devices, interrupting devices and a dedicated step-up transformer. These interconnection requirements are specific to the DG facility being installed and will not provide benefit to the utility distribution system (other than protecting the system from the DG facility in certain circumstances). HECO Companies' Response to PUC-IR-20.

Interconnection costs for DG facilities operating in parallel to the utility system should be paid for by the customer installing the DG facility prior to the utility incurring expenses to interconnect a DG facility. (For DG facilities exporting power to the utility grid, a DG interconnecting onto a distribution circuit to export power would theoretically receive avoided cost payments from the utility for the export of its power and the DG could evaluate the cost of the interconnection requirements with the forecasted avoided cost payments it would receive to determine if the project is economically feasible. HECO Companies' Response to PUC-IR-20.)

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for customer-sited generation operating in parallel to the utility grid. Exporting power onto the utility grid will change the direction of power flow on the utility's T&D system.

d. Time Frame for Interconnection

The time frame for completing an interconnection agreement will depend on several factors, such as whether a detailed technical study of the interconnection proposal is necessary, the timeframe for the customer (or third party) and HECO to work together to resolve any discrepancies in the single-line diagram, relay list, trip scheme and settings, and three-line diagram (required for generating facilities ≥ 30kW)[29], and the timeframe for the customer or third party to complete Exhibit B of the Standard Interconnection Agreement (Facility Owned by the Customer or Third Party Owner). Because of the case-by-case specifics that interconnection of a DG unit requires, it is not possible to provide a generic timeframe for the completion of an interconnection agreement as elements of the interconnection process are controlled by the customer, not by HECO. The timeframes for the steps in the interconnection agreement process for which HECO has responsibility are identified in Appendix III of Rule 14.H. Response to HREA-HECO-RT-1-IR-14; see Tr. (12/9/04) at 140-174.

2. Modifications To Rule 14.H Are Unnecessary

Rule 14.H does not need to be modified to further facilitate or encourage distributed generation. See HECO T-4, pages 28-29. Rule 14.H was developed based on the latest draft of the IEEE Standard 1547 and contains time frames for the initial technical review process and procedures for additional review and study processes. HECO also referenced other states' interconnection standards (California, New York, and Texas) when developing its interconnection standards. See Responses to HESS-SOP-IR-1; HESS-SOP-IR-2; HREA-HECO-T-4-IR-8; HREA-HECO-IR-13; HECO Companies' Response to PUC-IR-21.

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29 A complete application will include a completed Exhibit A of the Standard Interconnection Agreement (Description of Customer's Generating Facility), a single-line diagram, relay list, trip scheme and settings, and three-line diagram (for generating facilities ≥ 30kW). Response to HREA-HECO-RT-1-IR-14.

The HECO Companies will perform the same technical reviews (and study process), and will meet the same technical standards for their utility CHP installations as for non-utility CHP installations. See HECO RT-1 at 28-29; HECO Companies' Response to PUC-IR-21.

In addition, the HECO Companies stated that they would develop an interconnection guidance document to be shared with DG developers and customers, which could be posted on the HECO Companies' website. Tr. (12/9/04) at 180 (Seu).

B. ISSUE #10: WHAT IS THE APPROPRIATE RATE DESIGN AND COST ALLOCATION ISSUES THAT MUST BE CONSIDERED WITH THE DEPLOYMENT OF DISTRIBUTED GENERATION FACILITIES?

1. Introduction

In its direct testimony, the CA initially took the position that the utilities should "unbundle" their rates for customers who implement DG, and for customers that receive CHP service from the utilities.[30]

The HECO Companies' direct testimonies explained that their existing rates may understate the costs of providing backup service to customers who implement DG, but that that can be addressed by eliminating interclass subsidies, and realigning rates and costs to eliminate intraclass subsidies. Their testimonies also explained the reasons and basis for their proposed CHP service pricing, which can be viewed as a form of bundled pricing (although the cost of certain facilities such as absorption chillers are separated into an "unbundled" facilities charge).

The HECO Companies' rebuttal testimonies address the difficulties with implementing full unbundled pricing (i.e., pricing separately for generation service, auxiliary services, transmission service, distribution service, and billing and metering service), the lack of a need to incur the cost and commit the resources necessary to fully unbundle rates (since Hawaii has

found that retail competition should not be implemented), and the need to first align rates with costs before implementing full unbundling. The testimonies addressed the practical difficulties inherent in unbundling backup service and supplemental service from the rates for their own CHP service. There was also extensive testimony on the subject of standby rates, which is a mechanism for unbundling back up service and supplemental service provided to customers who install their own or third-party DG/CHP systems.

As a result of the settlement meetings, the HECO Companies', the CA's, and KIUC's positions now are aligned or are in agreement with regards to certain issues addressed in this docket including the issue on rate unbundling and cost-based tariffs for DG customers. The parties are in agreement with the following items in the matrix concerning rate unbundling and cost-based tariffs for DG customers:

Item 3.B.1. – "The Commission should require each utility to provide and have cost of service information and apply appropriate tariffs that result in a DG customer being served at a cost that is not subsidized by non-DG customers."

Item 10.A.1. – "The cost of service (i.e., T&D, ancillary services, etc) provided to DG customers would be identified and quantified in a cost of service study for each utility."

Item 10.A.2. – "The level of effort and detail for the cost of service study should be balanced with the information available, the cost of developing additional data, and the magnitude of the DG market and its impact on the utility's revenue recovery and revenue stability."

Item 10.C.1. – "Existing utility bundled rates should be supported by a cost of

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[30] The CA initially proposed the unbundling of electric utility rates in Hawaii, in an effort to address non-utilities' concerns regarding a level playing field as well as the utility's concerns over lost

service study such that DG customers compensate the utility for the costs of services provided."

As is illustrated by the foregoing, the appropriate end goal is to implement cost-based rates for all customers, including DG customers, rather than to simply unbundle rates. HECO Companies' Response to PUC-IR-25; see HECO RT-6 at 11-12. A matrix of the issues and the parties' positions is provided in HECO-R-601 and the same matrix is also provided in the CA's testimony as CA-RT-100.

The HECO Companies have applied these principles in determining the second condition (identified in Section I.A of the Opening Brief) for the HECO Companies to implement CHP service. The existing rates for backup and supplemental service charged to customers who install their own or third-party DG/CHP systems are not unfair, and may under recover fixed costs from such customers. This under recovery was addressed in substantial part on the Big Island, where the under recovery was most pronounced, through the implementation of the CA-Stipulated, Commission-approved Standby Rider A.

Nonetheless, the HECO Companies recognize that it will be appropriate to implement cost-based standby rates for HECO and MECO,[31] as well as for HELCO, and that the HELCO standby rider can be improved. At the same time, the record before the Commission is not complete enough for the Commission to mandate either the form of future standby rates, or the costs to be recovered in the standby rate components.

This can best be done in a follow-up proceeding, which should be in the form of a contested case framework proceeding, such as the Integrated Resource Planning Framework docket (so that the result will be supported by reliable, probative and substantive evidence),

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revenues. See CA-RT-1 at 31.

rather than a rulemaking proceeding. The actual standby rate schedules would then be implemented in rate case or separate tariff filings. In the meantime, the utilities should be allowed to propose interim, voluntary standby rates. Moreover, the conduct of such a follow-up proceeding should not further delay the implementation of utility CHP service.

Finally, COM has submitted a number of rate proposals in this proceeding (e.g., impact fees, inverted residential rates, TOU load factor block rates), which have previously been rejected by the Commission and/or should not be considered at the time (for reasons stated below and in Exhibit "D").

2. Existing Rate Design

Two primary rate design and cost allocation issues must be considered in the deployment of distributed generation, including issues arising out of: (1) existing cross-subsidization between the rate classes, and (2) existing recovery of a substantial portion of the Companies' fixed costs in their energy charges. Other issues generally stem from these two main issues. HECO T-5 at 11-12.

Appropriate rate design depends on who actually owns and operates the DG facility. The HECO Companies' rates are based on recovering the Companies' costs of providing service. The design of standby service rates will be based on the utility's costs of providing standby service. There are three basic steps in designing rates which include: (1) determination of the utility's total revenue requirements or the utility's total costs of providing service; (2) determination of each class' cost responsibility or allocation of the utility's total cost of providing service; and (3) rate design, which translates the class' cost of service into rates or prices. The services provided by the DG facility, if any and if significant enough, could impact the utility's cost of providing

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[31] This will become more important if existing rates and costs are more closely aligned, as recommended by the HECO Companies.

service (step 1 above) – and therefore, is indirectly taken into account. To the extent that the data on the DG facilities' operation characteristics as well as the standby load profile is available, and depending on DG market size, such information could impact the determination of the cost of providing standby service or the allocation of costs (step 2 above). The third step in the rate design process translates the class' cost into price or rates on the basis of some measurable variable, such as the customer's standby kW, which is normally based on the rated capacity of the DG facility that the Company is standing by. To the extent that data is available and/or measurable, the unit basis, i.e., determination of the billing standby kW, may take into account to the extent possible and reasonable, services that the DG facility will or could provide. HECO T-5 at 2; Response to HREA-HECO-RT-5-IR-2.

a. Cross-Subsidization Between Rate Classes

A cross-subsidy, as reflected in the HECO Companies' rates, is defined as the difference between a class's total full cost of service and the total allocated class revenue requirements that the rates are designed to collect. The class's total full cost of service is defined as the class's total revenue requirements at system average rate of return. Overall, the commercial rate classes historically and currently subsidize the residential class. In other words, the allocated residential revenue requirements that the residential rates are designed to recover is and always has been lower than the residential class's total full costs of service. The difference between the residential class's total full costs of service and the revenues produced from the residential rates are recovered from the commercial rate classes. HECO T-5 at 12.

HECO-501 provides a summary of the cross-subsidies reflected in the HECO Companies' current rates. HECO's Schedules H and F are also subsidized by the other commercial schedules (Schedules G, J, and P). For HELCO, Schedule H is also subsidized by

the other rate schedules (Schedules G, J, P, and F). For MECO, both Lanai Division and Molokai Division are subsidized by Maui Division. Response to HREA-HECO-T-5-IR-3

b. Costs Recovered In Each Rate Element

The HECO Companies' rate design is primarily based on embedded cost-of-service studies. The HECO Companies' rate design classifies the Companies' costs of providing service into the three cost components of: (1) demand-related costs, (2) energy-related costs, and (3) customer-related costs. Both demand-related costs and customer-related costs (together referred to as fixed costs) are incurred by the Companies regardless of the customers' energy consumption. For instance, if a customer reduces its kWh consumption, the Companies continue to incur the costs of operating and maintaining the plants and facilities required to serve the customer upon demand, and they continue to incur the costs of reading meters and billing the customer. HECO T-5 at 12-13.

The primary candidates for CHP systems are larger commercial service customers. The rates for large commercial and industrial power service (Schedule J, P, PS, PP, and PT) customers include a customer charge, demand charges based on kW demand blocks, and energy charges based on load-factor blocks. The energy charges under these rate schedules are designed to recover all of the energy-related costs and a significant portion of the demand-related costs, as well as a portion of the customer-related costs, that are not recovered in the demand and customer charges, respectively. The amount of fixed demand and customer costs recovered from the energy charges by rate schedule and by company are provided in HECO-502. HECO T-5 at 13.

Because the energy charges include fixed demand costs, the HECO Companies' load-factor block energy rate form is a mechanism for minimizing intra-class subsidy. HECO T-5 at 11. A low load factor customer with the same monthly peak demand as a higher load

factor customer pays for fewer kWh, and thus contributes less to the utility's fixed demand costs. The load factor block energy rate form ameliorates this inequity to some extent. This is important with respect to the implementation of DG by customers, because DG reduces the customers' load factors generally without reducing their monthly peak load.

c. **DG Deployment**

The cross-subsidies embedded in the HECO Companies' current rates, as well as the recovery of fixed costs in the energy rates, are important considerations in deploying DG.

First, a significant amount of the total full costs of serving the residential class are recovered from commercial customers. The use of DG by commercial customers causes the HECO Companies to suffer lost kWh sales. The loss of kWh sales from commercial customers adversely impacts the recovery of the residential costs of service that are subsidized by the commercial rate schedules. HECO T-5 at 13-14. In addition, the lost kWh sales from the commercial customers resulting from the use of DG impact the recovery of significant portions of the fixed costs that are embedded in the energy charges of the commercial rate schedules. HECO T-5 at 14. Thus, as the HECO Companies have pointed out in other proceedings, the loss of kWh sales due to DG could lead to increased rates for other ratepayers in the future. Depending on the DG market size, and the lost kWh sales, the rate increase impact on other ratepayers could be significant. As the deployment of distribution generation proceeds, interclass and intraclass cross-subsidization becomes untenable. HECO T-5 at 14.

Both the "load-factor block energy rate" and a rate structure that includes demand-related costs in the demand charges (and that does not include a significant portion of demand costs in the energy charges) are mechanisms for minimizing intra-class subsidies.

The cost recovery feature of the Companies' current load-factor block energy rate form is a mechanism for minimizing intra-class subsidy because most of the fixed demand and customer

costs that are not recovered from the demand and customer charges are embedded in the energy rate for the first load factor block. Since DG customers will be served under the current applicable rate schedules, absent a separate rate schedule for DG customers, the cost recovery mechanism of the Companies' declining load factor block energy rate form is appropriate with the deployment of DG as these customers will more likely have low load factors. Response to CA-IR-30.

A rate consisting of demand and energy charges that excludes demand-related costs from the energy charges (and includes them in the demand charges) would eliminate intra-class subsidy between low load-factor and high load-factor customers. Such a rate design would allow for fixed costs to be recovered in the demand charges and/or customer charges, allowing rate elements to be aligned closer to the cost components to provide more efficient pricing signals. Response to CA-IR-30.

d. <u>Realignment Of Rates And Costs</u>

The various factors considered in the HECO Companies' rate design process remain the same with the deployment of distributed generation. Depending on the form of DG market that emerges as a result of this instant proceeding, however, some of these considerations may vary in importance. HECO T-5 at 14.

Revenue recovery and revenue stability are important considerations in maintaining the financial integrity. This benefits all ratepayers in the long run. As noted earlier, the use of DG by commercial customers impacts the Companies' revenue recovery and revenue stability due to the cross-subsidies embedded in the rates, and the recovery of fixed costs in the energy rates. HECO T-5 at 14-15.

In the HECO Companies' next rate cases, the Companies should be allowed to align the costs and the rates more closely than has been allowed in past rate cases. Significantly more of

the fixed costs should be recovered in the demand charges and/or customer charges. This will align the rate elements closer to costs, and provide more efficient pricing signals. HECO T-5 at 15.

Realignment of rates and costs should occur even in the absence of the deployment of DG. Realigning rates and costs allows the utilities to more accurately recover their costs from the appropriate rate components and customers, and provides more efficient price signals to customers. Of course, reducing or eliminating the cross-subsidies between and within rate classes inevitably will have different rate impacts on individual customers in the various rate classes. Nonetheless, aligning rates and costs will ultimately benefit both the HECO Companies and the ratepayers.

3. Rate Unbundling

In general, rate unbundling requires separation of the utility rates into distinct service functions, such as generation, transmission, distribution, ancillary services, and retail supply. Rate unbundling has been made necessary in certain jurisdictions where the utility generation function has been deregulated and opened to competition. In these jurisdictions, competition is allowed for the generation, ancillary service and retail supply service functions, while transmission and distribution services continue to be delivered to wholesale or retail customers by the franchised utility. HECO RT-5A at 5-6; HECO T-5 at 16.

Unbundling of rates in jurisdictions that have allowed retail competition has been implemented, because traditional bundled rates are designed to recover costs related to all five functions, do not complement the introduction of competitive markets that rely only on the transmission and/or distribution network. In such restructured markets, non-utility competitors and their customers should only pay non-discriminatory prices for the unbundled transmission and distribution utility services they actually use. It appears that only those jurisdictions with

competition have undergone the process to approve a complete set of unbundled rates. Because Hawaii has not allowed retail competition,[32] rate unbundling is unnecessary. HECO RT-5A at 5, 7; HECO T-5 at 15. Furthermore, each island is a stand-alone system not interconnected with other utilities, and the islands are not interconnected. Therefore, there is no need to deliver or wheel power across the utility's system from one entity to another. HECO RT-5A at 5; see HECO T-5 at 15. Wholesale wheeling for sales to wholesale customers is also not a possibility because none of the utilities in Hawaii are interconnected. HECO RT-5A at 7.

In addition, rate unbundling alone is not a complete solution to designing rates for customers with DG, because the appropriate rate design for DG customers is different from that which is appropriate for customers who completely rely on the utility system to meet their full usage requirements. Because Hawaii has not authorized competition that includes the wheeling of power over the utilities' transmission and/or distribution networks, there is only a need to have a section in the existing tariff that lays out the special rate design necessary to accommodate customer-owned DG arrangements. It appears that similarly situated jurisdictions have also addressed this special case in the same way and have not completely unbundled rates. HECO RT-5A at 4.

Practical Considerations

The HECO Companies' cost-of-service study method already unbundles the total system costs or revenue requirements into the functional categories of generation, transmission, distribution, and customer service-related functions such as metering and customer-accounting and billing. The information required to further unbundle the costs of ancillary services is not

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32 For information on why Hawaii is unique and mainland models related to industry restructuring cannot be applied to Hawaii without recognizing the differences between Hawaii and the mainland, see HECO's Final Statement of Position in the Electric Competition Proceeding (pages 21-23), filed

available.[33] HECO T-5, at 15-16; See Responses to CA-IR-29.c, CA-IR-32.

Further, unbundling of rates would not make sense unless the cross-subsidies embedded in the HECO Companies' current rates were eliminated. Unbundling of rates is useful only if they reflect the true costs of service. See HECO T-5 at 12-14, 16; HECO Companies' Response to PUC-IR-25.

The HECO Companies' cost-of-service study may be expanded to include the DG customers as a separate class in the study, depending on the extent of the DG market that develops as a result of the DG policy framework from this docket, as well as the extent of availability of the required data. This is based on the presumption that, although DG customers who remain connected to the grid will continue to require and received bundled services from the HECO Companies, the degree and level of their requirements for these services may be different from the customers who receive their entire electric power requirements (full requirements customers) from the HECO Companies. For instance, the DG customers' requirements for generation and generation-related ancillary services may vary between DG customers, and may be different from those of full requirements customers. The proper assessment and determination of the costs caused by DG customers will depend on the availability of required data such as, but not limited to, data regarding (1) the customers' DG capacity sizes, also their DG unit availability rates, (2) the frequency and duration of their DG unit downtimes, (3) DG outage verification and reporting, and (4) customer load characteristics such as system peak coincident demand. HECO Companies' Response to PUC-IR-25.

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in the Collaborative Report, October 19, 1998, Docket No. 96-0493, as well as the Commission decision and order, in the competition docket.

33 The CA agreed that cost allocation studies can be difficult, time consuming, complex and involve a certain amount of judgment, and are often contentious. Tr. (12/8/04) at 193-94 (Herz).

Furthermore, the rate unbundling process is usually lengthy and administratively costly for the regulatory agency and the interested parties. HECO RT-5A at 6. Although a "revenue neutral" unbundling can be somewhat less administratively burdensome, this would still require careful development of the underlying functional costs to determine appropriate ratios used to separate the revenue requirements of each customer class into the various functions before the unbundled rates are computed. While a revenue neutral unbundling may work the first time rates are unbundled, eventually the Commission will be faced with a new cost of service study designed for unbundled rates in future rate applications to adjust rates. At such time, the Commission will be faced with a difficult decision as to how to treat any subsidies that may be embedded in current rates. Complete removal of subsidies can cause significant rate increases for certain customer classes. One method would be to unbundle the subsidies as a stand alone rate element charged to each customer, thereby making them transparent to all, but the Commission should expect increased pressure to eliminate the subsidies once they become so visible. Such a subsidy rate element would be positive for those customer classes that provide the subsidy and negative for the customer classes receiving a subsidy. HECO RT-5A at 6.

4. Standby Rates

a. Standby Service

Customers who generate some or all of the electricity that they normally use (referred to as "DG Customers") generally want to purchase power from the HECO Companies when their own generators or alternate suppliers are not running for any reason, to guarantee adequate and continuous supply of electricity. These customers typically remain connected to the utility grid. HECO T-5 at 17. Standby service is provided by a utility to allow a DG customer an opportunity to reserve the assurance that the utility will provide and deliver that power to that customer at times when the customer's own DG is unavailable. Because complete disconnection from the

utility's network would require the customer to own and maintain its own backup power source and follow its own load precisely, most DG customers are likely to find network attachment to be the more attractive option. HECO RT-5A at 10.

HECO and MECO serve these customers under the standard commercial rate schedules (Schedules J, P, PS, PP, or PT), and there is no separate standby charge. HELCO serves these customers under the standard commercial rate schedules in conjunction with Rider A – Standby Service. HECO T-5 at 17.

HECO and MECO recognize that they need to implement standby rates as the use of customer-owned (or third-party owned) DG/CHP systems continues to expand. HELCO has already implemented standby rates, because its existing rates significantly under recovered fixed demand costs from lower load factor DG Customers. HECO and MECO have not found it necessary to do so, because the problem is less pronounced on Oahu and Maui. (Their service areas are more dense, and they have less T&D plant per customer kW load served than HELCO. Thus, they recover a lower percentage of fixed demand costs through their energy rates.) If, however, their demand charges are allowed to fully recover demand costs, then DG Customers will be pressing for standby rates (based on claims that regular rates will then <u>over</u> recover the demand costs attributable to DG Customers.)

Dr. Gegax, the HECO Companies' consultant on this issue, pointed out that the appropriate rate design to accommodate the special nature of customer-owned generation differs from the rate design for full-requirements customers. The rates, in part, must be based on reserved capacity requirements of the DG customer to ensure that the customer can be accommodated when the DG facility is unavailable. To cover the costs related to standby service, customers that own DG, but remain connected to the utility's network, may require an

adjustment to their existing tariffs. As a result, other jurisdictions (including those with unbundled rates) have implemented this special rate design through a modification of the existing tariff (i.e., through a standby rate provision). HECO RT-5A at 4-5, 10.

Thus, the real issue is not whether cost-based standby rates should be implemented, but how to implement standby rates so that they are cost-based to the extent practical. In this regard, there is substantial disagreement as to what costs are attributable to DG Customers. Moreover, the answer depends on the maximum amount of DG load that the HECO Companies must standby to serve (i.e., be ready to serve) at any given point in time - - and, thus, the answer should take into account the actual characteristics of the customer-sited DG load on the system (which will change over time).

b. Implementation of Standby Rates

The utility system remains available at all times to make up the moment-to-moment difference between DG customers' electricity usage and the amount of electricity produced by their generation, and from time-to-time the utility will have to meet the full energy needs of various DG customers with utility-generated electricity. The distribution, transmission, and generation capacity built into the utility's system must be sufficient to meet this moment-to-moment variation in their demand as well as the DG customers' full demand when the customers' generation is not producing electricity. There are costs associated with this utility system capacity, which continue regardless of usage. These costs should be recovered from DG Customers throughout the year, not only during the times when the customers actually use the capacity to deliver additional energy. Therefore, the appropriate design of rates for DG Customers based on cost-causation principles would include a demand charge large enough to recover the full costs associated with the capacity necessary to meet the customer's full demand at any time. HECO RT-5A at 13-15.

The utility's transmission and distribution system must be built and maintained to accommodate a DG customer's maximum load even if some of this load is satisfied by the customer's DG, to accommodate for the periods when the DG is unavailable. Most of the utility's cost of providing standby assurance is associated with the fixed costs of the transmission and distribution system, and a portion of the fixed costs of generation, as well as additional customer-related costs associated with any additional metering and billing.

The full cost related to distribution capacity should be included in any standby reservation charge, because this capacity is necessary to fulfill the standby assurance benefiting the DG customer. HECO RT-5A at 10-11. While it can argued that the full cost of transmission capacity falls in the same category, it can also be argued that a portion of the transmission capacity (the "bulk transmission" component) is sized based on the generation capacity. To the extent that this is the case, only a portion of the bulk transmission cost would have to be recovered from DG customers.

Standby service rates should only include a portion of the fixed costs associated with generation. The utility's total investment in generation includes (1) capacity that is required to satisfy the expected demand of its customers, and (2) reserve capacity that is required for unexpected generation outages and other ancillary services necessary to ensure system reliability. HECO RT-5A at 11.

Full requirements customers are allocated their share of the costs related to both categories of generation capacity. The DG customer, on the other hand, has made an investment in generation capacity which, when available, satisfies a portion of its energy needs. Therefore, DG Customers have self-provided the first category of generation capacity listed above in order to cover a portion of their load. DG Customers, however, have not self-provided the capacity

identified in the second category listed above. Therefore, the generation capacity cost attributable to DG Customers includes an allocation of the utility's costs associated with the second category of generation capacity. HECO RT-5A at 10-11.

The portion of the DG customer's load that is not satisfied its DG capacity (which is generally termed "supplemented service") is subject to the rates in the existing tariff; that is, the rate elements that include the fully allocated cost of all utility functions provided by the utility. HECO RT-5A at 12.

In addition, any costs associated with new facilities, such as metering and distribution system upgrades that may be required to accommodate DG, should be recovered from the DG Customer for standby service. These costs may need to be determined on a case-by-case basis. Furthermore, variations in the type of technology employed across DGs can affect ancillary service requirements and, hence, utility system costs. Those costs would also have to be identified on a case-by-case basis. HECO RT-5A at 12.

c. **HELCO's Standby Rider A**

A standby service provision was proposed on the Big Island because of HELCO's concern that application of its existing rate schedules to customers with on-site generation would not cover the cost of providing backup service to such customers. The goal in designing Rider A was to set fair and equitable rates that reasonably recover the costs of providing standby service from standby customers imposing such costs.[34] HECO T-5 at 17.

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[34] The design of HELCO's Rider A was based on two principles. First, the standby service rates should be fair to the customers while reflecting the unique characteristics of the utility system, the costs of providing the service, the requirements placed on the utility system by the standby service customer, and the impacts on other customers. HECO T-5 at 17.

In addition, standby service rates should send proper price signals, such that economically efficient decisions on the part of self-generators to secure standby service result. Standby service rates should not encourage uneconomic bypass or encourage inefficient use of standby service to the detriment of other customers. Uneconomic bypass occurs when the cost of a customer's alternative

It has been suggested that HELCO simply "repeal" Rider A. HELCO appreciates the unresolved nature of the concerns raised on standby charges. HELCO's position is that Rider A should continue to apply to non-utility DG/CHP installations unless it is determined that that would be unfair after HELCO enters the CHP business on a regulated basis. Thus, in the HECO Companies' CHP Program application, HELCO requested either (1) a finding that continued application of the standby service rider is fair in light of its proposed CHP pricing, or in the alternative (2) a determination that application of the standby service rider to non-utility DG/CHP installations should be made voluntary. If Rider A is modified to make it voluntary, current Rider A customers (as well as customers that have DG/CHP systems installed in the future) will have the opportunity to sign up for the Rider A option. If they do not elect to sign up for the Rider A option, they will not be subject to any Rider A charges, and will receive all service under the appropriate regular rate schedule.

Subsequently, HELCO has consulted with the CA as to its views on the continued fairness of the standby service rider, since HELCO and the CA stipulated to the form of the standby service rider approved by the Commission. HELCO's understanding is that the CA continues to support HELCO's Standby Rider, because it unbundles the costs of providing backup service to DG customers.

If the Commission determines that Rider A should be made voluntary in order to alleviate concerns that Rider A will impede the efforts of competing suppliers of DG/CHP systems, then HELCO stated that it would file a revision to Rider A (using the 30-day notice provisions of

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source of electrical energy is lower than the cost of receiving service under HELCO's applicable standard rate schedule, but higher than HELCO's marginal cost of providing service. Due to the manner in which rates have been established in Hawaii, HELCO's rates for its large commercial customers are not only higher than HELCO's marginal costs, but also are higher than its average embedded costs of providing service to such customers. HECO T-5 at 17-18.

HRS Section 269-16(b)) as soon as a determination has been made that HELCO will be permitted to provide CHP services to customers. HECO T-5 at 18-19.

d. Form of Standby Rates

COM has recommended that standby charges be implemented so that "each DG customer contributes to the cost of owning and maintaining the capacity that collectively provides service to all DG customers in proportion to how much and how often the individual customers use that standby capacity." COM RT-2 at 18 (emphasis added). In support of this proposal, COM states that, because not all customers are expected to be out of service simultaneously "it is only necessary for the utility to have a fraction of the combined DG capacity installed on its system in reserve in order to meet the standby needs of these customers." COM RT-2 at 18.

COM's recommendation, and its exhibits showing a very low reservation charge (for illustration purposes), ignited an extended debate at the panel hearing. See Tr. (12/9/04) at 201-267; Tr. (12/10/04) at 51-61, 67-70, 74-88, (Jim Lazar, Dr. Doug Gegax, Estrella Seese, Mike Gregg, Joe Herz). The only thing that was clear when the dust settled after the panel hearing on Issue# 10, however, was that the issue was unresolved.

5. Utility CHP Pricing

The HECO Companies propose to serve their CHP customers under their regular applicable rate schedule in conjunction with the proposed Schedule CHP. Schedule CHP's rate elements are adjustments to the applicable rate schedule and include the following:

(1) a specified Energy Rate credit, that differs between HECO, HELCO and MECO, which is applied to the kWh supplied by the CHP unit, subject to a minimum guaranteed discount based on 85% availability of the CHP unit;

(2) a Facilities Charge, which is based on the absorption chiller applicable to the CHP customer's CHP system; and

(3) a Base Thermal Charge for the thermal energy supplied by the CHP unit, which is adjusted up or down in the CHP Agreement based on the characteristics of the particular CHP system installation.

The determination of the proposed Schedule CHP rates and charges is discussed in detail in the Companies' CHP Program application in Docket No. 03-0366, beginning on page 22. HECO T-5 at 21-22.

Certain parties have questioned whether any CHP system, regardless of ownership by the utility or a non-utility entity, should be assessed the same rates and charges for standby service. Such an approach would not serve any real purpose. The utility would have to (1) charge different rates than those based on its rate schedules for CHP system electricity (i.e., for CHP service), and (2) charge for "supplemental" service (i.e., electricity from the grid) based on their rate schedules, and charge for backup service based on a standby charge. If the utility's CHP system performed well, it would receive more revenues for CHP service and less for back-up service. If the CHP system performed poorly, the utility would receive lower revenues for CHP service and more for back-up service. The customer would be indifferent (as long as the CHP system thermal output was sufficient for its needs) since the utility would provide both services. A standby charge makes sense where the providers of CHP service, and backup and supplemental service, are different entities. HECO RT-1 at 31; see Response to CA-IR-15.b.

As Dr. Gegax testified, if the DG facility is utility-owned and part of the utility rate base then, like central generation stations, the electricity provided by the DG facility is simply utility provided power. If the DG facility is located on the customer's premise then the customer's existing tariff can continue to be applied with two primary adjustments. First, an adjustment in the form of a discount to the bill would be appropriate in recognition that: (1) the customer is

providing a site free of charge; (2) DG facilities such as combined heat and power ("CHP") systems use fuel more efficiently; and (3) DG facilities may result in the postponement of new transmission and central generation investments. Such a discount can be calculated through an energy credit applied to the total kWhs produced by the DG facility. Second, in the case with CHP systems, the capital costs of non-electricity generating components (i.e., cooling towers and absorption chiller units) used directly by the customer, and only the customer, would need to be recovered through an additional charge so that the full cost of such components are not paid for by non-participating customers. HECO RT-5A at 9.

Ideally, utility-owned DG facilities would be on the utility side of the meter. However, in situations where they are not, the output of the DG facility can be added to the input from the utility's network in order to determine the customer's total consumption. Because both sources are metered, the two adjustments mentioned above can still be implemented to the existing tariff. HECO RT-5A at 9-10.

6. Customer Retention Rates

A number of parties criticized the HECO Companies for their use of customer retention rates. Other non-utility parties to this docket have alleged that the HECO Companies could effectively discourage DG participation by providing discounted rates to potential DG customers by means of customer retention contracts to prevent installation of non-utility customer sited DG. See CA-RT-1 at 22; see, e.g., Tr. (12/09/04) at 19-21 (Gregg).

In general, customer retention rates are designed to retain loads for recovery of fixed cost-related revenues from customers with viable alternative energy suppliers. These energy rate discounts such customers receive result in lower future rate impacts than the alternative of losing the entire load and its contribution to recovery of fixed costs which would be shifted to other ratepayers. Response to HREA-HECO-T-5-IR-5.

Currently, in light of the filing of the HECO Companies' CHP Program application on October 10, 2003, Docket No. 03-0366, and the evolution of the HECO Companies' approach to DG/CHP, HECO and HELCO have reevaluated the applicability of Rule 4 load retention contracts. HECO T-5 at 20. In HECO's 2005 test year rate case, HECO has proposed to discontinue the Standard Customer Retention Rate provided for in HECO's Rule 4, Section D. See e.g., Docket No. 04-0113, HECO T-22 (E. Seese) (filed November 12, 2004) at 51.

a. Rule 4 Contracts

The HECO Companies' Rule 4 Standard Form Contracts for Customer Retention were designed to retain loads for recovery of fixed cost-related revenues, and not for the purpose of retaining specific customers. The basis for the contracts was provided in Docket No. 99-0106 for HECO, and Docket 99-0177 for HELCO. HECO T-5 at 20; citing HECO Companies' Response to Informal Complaint No. IC-03-098, filed August 5, 2003, Part I, Appendix A at 5-6; CHP Program Application, at 5, fn. 3, Docket No. 03-0366.

Within the HECO Companies, Rule 4 Standard Form Contracts for Customer Retention are only in effect for HECO and HELCO. MECO does not have a Rule 4 Standard Form Contract for Customer Retention rate. COM-HECO-DT-IR-45. Rule 4 Contracts for Customer retention provide specified rate discounts for Schedules J, P, PS, PP, and PT customers who have viable alternate energy suppliers other than the HECO Companies. The energy rate discounts offered under the Rule 4 Rate Contract were set at amounts less than or equal to the percentage "subsidy" borne by the rate class (HECO and HELCO's Schedules J and P). Thus, even with the discount, the rates under the Rule 4 Rate Contract were still well above marginal costs. Currently, HECO has no Rule 4 Rate Contracts. HELCO had a three-year Rule 4 Rate Contract with the Hilton Waikoloa Village, which became effective December 10, 2001, Transmittal No. 02-01H, filed January 14, 2002.

MECO does have a service contract with Castle & Cooke, LLC, which was filed and approved in Docket No. 03-0261. HECO T-5 at 19-20. However, the terms of MECO's service contract with Castle & Cooke were the result of negotiations between the parties, and MECO does not have a Rule 4 Contract for Customer Retention. Response to COM-HECO-DT-IR-45.

The justification for the discount to Castle & Cooke Resorts is addressed in the application filed on September 17, 2003 in Docket No. 03-0261. The CA, in its Statement of Position indicated, based on its review, that the discount was reasonable. In Decision and Order No. 20811, the Commission likewise found the discount to Castle & Cooke Resorts to be reasonable and in the public interest, particularly in light of potential loss of revenues to MECO and the impact on the remaining ratepayers. In light of this finding, the Commission approved the contract. Response to COM-HECO-DT-IR-45.

MECO, in its application to the Commission in Docket No. 03-0261, proposed the discount while also contemplating the installation of a utility-owned CHP system at a time closer to the need date for additional generation on the island of Lanai. The third party proposal was for a combination of CHP and customer-sited electrical generation, at a magnitude such that the customer would have completely bypassed the MECO system on the island and caused MECO to lose 40% of its Lanai sales. Thus, in response, MECO offered the discount, and helped facilitate the installation of a number of energy conservation measures, to defer the customer's CHP project, and to encourage the customer to plan a CHP project (whether utility, third-party, or customer owned) that would be better sized and timed to fit with the island's overall generation needs. Response to CA-IR-11.

The CA took the general position that unbundling the current rate structure could be a better mechanism for dealing with situations such as that on Lanai. CA T-1 at 43-44.

Unbundled rates, however, would not have addressed the unique situation that occurred on Lanai, whereby a major customer contemplated bypassing the utility system for a significant portion of its load, which would have resulted in a significant loss of sales to the utility, and would have adversely impacted the rates for the remaining customers on the system. If the customer bypassed the utility system, then it would not be relevant whether the rates were unbundled or not – the customer would not be taking service from the utility and consequently there would be no revenue stream to the utility. HECO RT-1 at 57-58.

7. Specific Rate Issues Should Addressed In A Different Docket

Some parties have used this docket as a venue to raise rate issues that appear to go well beyond the scope of this proceeding. However, a determination of these rate issues at this time would be inappropriate and premature.

The CA is in agreement with this position. At the hearing, the CA explained that rate issues should be left for rate proceedings. In addition, in its direct testimony, the CA specifically noted that ". . . the actual implementation of DG policies resulting from this proceeding, especially cost allocation and rate design for purposes of developing specific rates, should be addressed in separate proceedings on a case by case basis for each utility." CA RT-1 at 8. Further, the CA recognized that "[m]any of COM's rate design proposals, however, have implications beyond DG considerations and could impact social policies such as Hawaii's Island development and growth policies and objectives." CA RT-1 at 30.

COM has recommended that the Commission "open a generic rule making proceeding to address all of the rates and fee issues recommended by the Parties to this proceeding." CA-RT-1 at 30. The Commission has too many ongoing proceedings to justify opening a generic ratemaking proceeding on rate issues. Most of these issues are better decided on a case-by-case

basis. The HECO Companies would support a generic proceeding on standby rates, but recommend that the Commission not use a ratemaking proceeding for their purpose.

C. ISSUE #11: WHAT REVISIONS SHOULD BE MADE TO THE INTEGRATED RESOURCE PLANNING PROCESS?

1. IRP Process (Background)

Through the integrated resource planning ("IRP") process, the HECO Companies, with input from Advisory Groups, develop long-range resource plans containing various types and sizes of supply-side and as demand-side resources. The HECO Companies apply their capacity planning criteria to determine the appropriate years in which the resources should be installed. In general, capacity must be added to the system when the capacity planning criteria cannot be satisfied. Other factors are also taken into account that could also affect when additional firm generation would be required. These factors include the mix of generation resources, minimum demand considerations, required power purchases, supplemental energy purchases, purchase power uncertainties, transmission considerations, and system stability considerations. HECO T-3 at 3.

2. No Changes Are Necessary

No changes to the IRP Framework are required for the consideration of distributed generation. HECO T-3 at 12. The Consumer Advocate is in agreement with the Companies on this issue, stating that "No revision to the Framework is required". CA-RT-1 at 44. In the current round of integrated resource planning for HECO (IRP-3), DG and CHP technologies are analyzed extensively, and a significant effort is being made to consider DG and CHP technologies and their potential contribution to meeting the electrical needs of HECO customers. HECO RT-4 at 1; see also HECO RT-2 at 6.

By its nature, however, DG is difficult to analyze in this process. The IRP process analyzes resources at the system level prior to the identification of specific projects. In addition, an individual DG project is generally too small to impact the timing of central station units or transmission line timing. For these reasons, DG must be considered on a generic basis without consideration of the specific impacts a particular project may have on the system that are site specific. In order to complete a fair evaluation, an aggregate forecast of DG resources must be developed, as was done for CHP system in the analysis done for the CHP Program application in Docket No. 03-0366. HECO T-3 at 12.

D. The HECO Companies Consider DG In Their IRP Processes

The HECO Companies are evaluating DG and CHP in their current integrated resource planning processes (IRP-3)[35]. HECO T-3 at 13-14. HECO's IRP-3 is currently in progress in Docket No. 03-0253 and is targeted for filing no later than October 31, 2005. HELCO's IRP-3 is also in progress in Docket No. 04-0046 and is scheduled to be filed no later than October 31, 2005. MECO's IRP-3 is currently in the very early stages and is scheduled to be filed by October 31, 2006 in Docket No. 04-0077. Response to HREA-HECO-T-3-IR-3.

Within the overall IRP process, DG/CHP will be evaluated from the generation capacity planning, transmission planning and transmission and distribution planning perspectives to the extent practical. HECO RT-3 at 11-12.

1. DG/CHP in Generation Capacity Planning

With respect to generation capacity planning, the IRP process will determine the need for new generating capacity based on a forecast of future electrical demand, the extent to which that demand can be reduced through demand-side management programs, and the extent to which the

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[35] Their earlier consideration of DG and CHP in their IRP-2 Evaluation Reports is addressed in the HECO Companies' Response to HREA-HECO T-3-IR-3.

need for reserve capacity can be reduced through load management programs. Once that need is determined, the HECO Companies will evaluate various options to satisfy that need. Those options include DG, CHP, renewable energy and central-station generation. HECO Companies' Response to PUC-IR-34.

HECO's IRP-3 evaluation will consider two levels of market sizes. The evaluation will also include a supplemental sensitivity analysis which takes into account the revenue impacts from the discount to electric rate tariffs, facilities charges, and thermal charges. The revenue impact analysis cannot be performed during the base integration analysis because the dynamic optimization computer model used for the integration analysis does not have a means to evaluate this. This evaluation must be done outside of the model in a supplemental analysis. This supplemental analysis will estimate the HECO Companies' CHP Program impacts on non-participants. HECO RT-3 at 11. The analysis will also consider changes in utility revenues due to discounts to electric rate tariffs, facilities charges and thermal charges. HECO Companies' Response to PUC-IR-34.

Even if not specifically identified in the integrated resource plan, other DG and CHP projects can still be pursued. Because CHP projects are largely driven by customer need, it is difficult, if not impossible, for the Companies to identify all potential CHP projects. Therefore, after HECO's IRP-3 preferred plan and five-year action plans have been finalized and filed with the Commission, new CHP or DG opportunities not identified in the resource plan or action plan may arise. HECO should not be precluded from pursuing these opportunities. HECO RT-3 at 13.

2. DG/CHP in Transmission & Distribution Planning

DG and CHP will also be evaluated in HECO's transmission and distribution planning processes to the extent practical. In summary, based on forecasts of electrical demand, HECO's

transmission and distribution planning criteria will be applied to determine where and when planning criteria violations will occur and to identify any reliability concerns. When these planning criteria violations or reliability concerns are identified, the HECO Companies evaluate possible solutions. DG or CHP are considered as potential solutions. HECO Companies' Response to PUC-IR-34; see HECO RT-4 at 1-15 (for a thorough discussion of how DG and CHP will be evaluated in HECO's transmission and distribution planning processes).

Based on forecasts of electrical demand, HECO's transmission and distribution planning criteria will be applied to determine where and when planning criteria violations will occur and to identify any reliability concerns. Once these planning criteria violations or reliability concerns are identified, HECO evaluates possible solutions. DG or CHP are considered potential solutions. HECO Companies' Response to PUC-IR-34.

a. Transmission Planning

DG/CHP will be considered in the transmission planning process on a system wide basis. With respect to transmission planning, in the HECO IRP-3 process, HECO will select a few candidate long-term resource plans, with the specific assumptions on the sizes, locations and operating costs for future central station generating units, and perform load flow analyses. In order to account for the impacts from DG/CHP in the long-term analyses, without identifying specific locations for the DG/CHP units, forecasted DG/CHP and any additional DG/CHP above what is already being forecasted will be allocated on a system wide basis using the historical loading at the transmission substations. HECO will identify the timing and location of transmission planning criteria violations and evaluate the effectiveness of some possible solutions. Since the transmission analysis will also consider DG/CHP, the evaluated solutions will include mainly transmission system upgrades or additions. In addition, if the transmission analysis for the IRP processes identifies transmission constraints, additional detailed studies must

be performed outside of the IRP process for the preferred plan approved by the Commission to further evaluate, using both transmission capacity options and load reduction options, the identified constraints and the possible solution identified in the IRP process. HECO Companies' Response to PUC-IR-34; see HECO RT-4, at 1-12.

In order to perform a transmission analysis, assumptions with respect to size, location and operating costs for future generation will be made and impacts of DG/CHP on a system wide basis will be incorporated into the HECO IRP-3 process. HECO RT-4 at 14-15.

b. Identification of "Load Pockets" Within IRP Process

HREA has suggested that, within the IRP process, the HECO Companies should "identify the amounts, timing, locations and any locational restrictions, such as an inability of a circuit or area of the system that is already at its maximum for "as available" power to handle more than "X" kWs without system upgrades." See HREA-T-1 at 12. The Consumer Advocate defined and termed similar information as identified "load pockets." See CA-T-1 at 13-14.A. HECO RT-4 at 12.

Through the IRP process, it may be possible to identify larger geographic areas that require additional generation and/or have transmission constraints. For instance, HELCO's IRP-2 report identified preferred locations on the West Side of the Big Island for future generation in Section 8.6.2. The March 2004 HELCO IRP-2 Evaluation Report updated this information. Identifying the amounts of DG/CHP required and the timing for the DG/CHP to mitigate identified transmission criteria violations and/or reliability concerns ("transmission constraints") can be done for a few finalist plans only if identified transmission constraints are triggered by load demand growth and not by the addition of generation. The amounts of DG/CHP required to mitigate transmission constraints will be specific to the assumptions of the analysis, and will not take into consideration the practical issues involved with projecting when and where DG/CHP

will be installed on the system and attempting to rely on the installation of large amounts of area-specific DG/CHP. Therefore, the ability to achieve the specific amount of DG/CHP to mitigate the transmission constraints would be uncertain, and reliance on such uncertain "solutions" can create problems for the transmission system. HECO RT-4 at 12.

Thus, the IRP process already identifies certain geographic areas where DG may be able to provide the most benefit. However, identifying the amounts of DG/CHP required and the timing for the DG/CHP to mitigate identified transmission constraints can be done for a few finalist plans (but only if the identified transmission constraints are triggered by load demand growth). Relying on achieving specific targets of DG/CHP to mitigate transmission constraints can be unreliable and, therefore, DG/CHP should be considered on a system-wide basis. HECO RT-4 at 15.

c. **Distribution Planning**

Planning for the distribution system will not be incorporated into the IRP process because of the variability and time frame for the distribution system load forecast. However, the Distribution Planning Process is conducted in a manner consistent with the IRP process on a project-specific basis to the extent practical. HECO RT-4 at 2.

With respect to distribution planning, DG/CHP will be considered in the distribution planning process through a series of orderly steps, as in the transmission planning process, but with some significant differences. See HECO RT-4 at 8-9. There are significant difficulties in considering DG/CHP in the distribution planning analysis in IRP. Finally, because of the variability and the time frame for the distribution system load forecast, distribution system impacts will not be incorporated into the long-range plan for the HECO IRP-3. However, the Distribution Planning Process is consistent with the IRP planning process and takes into

consideration Load Reduction, DG at Substations and Distribution Capacity solutions on a project-specific basis. HECO Companies' Response to PUC-IR-34.

E. ISSUE #13: WHAT REVISIONS SHOULD BE MADE TO STATE ADMINISTRATIVE RULES AND UTILITY RULES AND PRACTICES TO FACILITATE THE SUCCESSFUL DEPLOYMENT OF DISTRIBUTED GENERATION?

1. No Changes Are Required To State Rules And Utility Rules And Practices

No changes are required to state administrative rules and utility rules and practices to facilitate the successful deployment of distributed generation. Existing statutes, rules, and regulations adequately provide for non-utility ownership of DG. The HECO Companies have explained in detail above that the proposed utility CHP Program would not unfairly impact non-utility developers of DG/CHP and competition would exist in the market. Non-utility DG developers are not competitively disadvantaged when compared to the regulated utility's own development of DG, especially with regard to large national DG developers that are established in Hawaii. HECO RT-1 at 33; HECO Companies' Response to PUC-IR-2.

2. Commission Should Approve

To facilitate the successful deployment of DG, the Commission should approve the HECO Companies' proposed CHP program and CHP tariff, and expeditiously review and approve applications for individual CHP projects under Rule 4 of the Companies' tariffs. The HECO Companies' CHP programs and tariffs are designed to enable them to respond to the needs of CHP customers in a timely and efficient manner, by streamlining the review and approval process. HECO T-6 at 11.

3. DG Definition Is Appropriate

As defined by the Commission in this Docket, DG involves the "use of small-scale electric generating technologies installed at, or in close proximity to, the end-user's location". For purposes of this docket, this definition is sufficient. A more detailed definition of DG (i.e.,

identifying eligible technologies) would be necessary only if the Commission intends to somehow regulate or limit utility activities pertaining to DG, and develops specific rules or policies for particular types or sizes of DG. Under HECO's proposed CHP Program and Schedule CHP tariff, a definition of DG is unnecessary as the proposed Program clearly delineates the CHP technology and its application. HECO Companies' Response to PUC-IR-4.

4. Utility Program Fits Within The Definition Of Successful Deployment Of DG

The HECO Companies' proposed CHP program falls within the term "successful deployment of distributed generation", because the CHP installations would be cost-effective in the IRP sense (based on the quantifiable and qualitative costs and benefits addressed in the CHP Application) and would facilitate customer choice. The "successful deployment of distributed generation" also should avoid undue impacts on utility systems, and on non-participating utility customers. The HECO Companies have already taken steps to address the impacts on utility systems through the deployment and approval of Tariff Rule 14.H. The Companies' participation in offering CHP systems through their proposed CHP programs and Rule 4 contracts would help avoid undue impacts on non-participating customers. HECO T-6 at 11-12.

5. No Changes To Hawaii's Net Energy Metering Law Are Necessary

HREA claims that the size limitations in Hawaii's net energy metering law was set without a detailed assessment of offsetting benefits that net metered systems provide. HREA T-1 at 9. This issue appears to be beyond the scope of this generic docket, which generally addresses the generic framework from a utility regulatory perspective, for DG in Hawaii. HECO RT-6 at 10-11.

To further increase renewable energy development in Hawaii, the 2004 legislature updated the net energy metering law in Act 99, Session Laws of Hawaii, effective June 2, 2004.

HECO-RT-6 at 11; PUC-IR-3. Under Act 99, the legislature increased the size of the facilities qualifying for net energy metering from 10 kilowatts to 50 kilowatts. HECO-RT-6 at 11. In general, the update increased the allowable size of renewable energy technologies in the NEM law from 10 kW to 50 kW (see HECO T-2, pages 22-23 and HECO RT-6, pages 10-11). HECO Companies' Response to PUC-IR-3.

Any further changes at this time to the net energy metering law (i.e., increasing the size limitation) would be premature, since the current legislative change has been in effect for less than a year. HECO supported expansion of the 10 kW limit to 50 kW this past legislative session, recognizing that the 50 kW amount may introduce interconnection considerations that are different than those associated with 10 kW facilities (see HECO RT-6, page 11). HECO understood the Hawaii State Legislature's desire to increase renewable energy development via the NEM law rather than the broader DG technologies. HECO Companies' Response to PUC-IR-3.

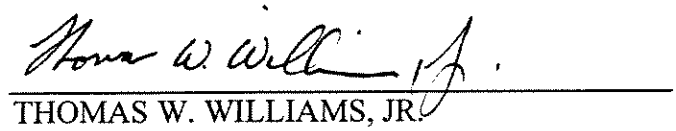
In particular, increasing the size limit beyond 50 kW would raise a number of concerns. For example, as the size of NEM systems increase, interconnection of the customer generator with the utility grid increases in complexity. A large-scale installation will likely have unique interconnection considerations depending on its size and location on the system, and safety becomes an issue. As larger NEM systems are considered, it is important to understand safety, reliability, and power quality issues. The Commission has recently approved new interconnection standards and a standard interconnection agreement for generators operating in parallel with the Companies' utility systems (as specified in Rule 14 Section H, Decision and Order No. 20056, Docket No. 02-0051, approved by PUC on March 6, 2003). The 2004 Legislature updated the NEM law which states that the larger generators (greater than 10 kW)

can follow these interconnection procedures as approved by the PUC, including the customer insurance requirements. The new NEM statute will help ensure interconnection issues such as power quality, protection of both utility and customer equipment, reliability, and safety of maintenance workers are taken into consideration. HECO Companies' Response to PUC-IR-3.

V. CONCLUSION

Based on the foregoing discussion of the issues, and the reliable, probative and substantial evidence in the record in this proceeding, the HECO Companies respectfully request that the Commission expeditiously authorize them to proceed with the installation of utility-owned, operated and maintained CHP systems at customer site (pursuant to Rule 4 CHP Agreements and their proposed CHP Program), subject to the conditions proposed in Section I of this Opening Brief.

DATED: Honolulu, Hawaii, March 7, 2005.



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