HECO RT-4
DOCKET NO. 03-0371

REBUTTAL TESTIMONY OF

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Subject: Distributed Generation/Combined Heat & Power and the Transmission and Distribution Planning Process

INTRODUCTION

Q. Please state your name and business address.

A. My name is Shari Ishikawa and my business address is 820 Ward Avenue, Honolulu, Hawaii.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted written direct testimony and exhibits as HECO T-4.

Q. What is the scope of your rebuttal testimony in HECO RT-4?

A. My rebuttal testimony will cover:

1) Distributed Generation ("DG")/Combined Heat & Power ("CHP") and the Transmission and Distribution Planning Process.

Q. On whose behalf is your testimony submitted?

A. My testimony is submitted on behalf of Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO") and Maui Electric Company, Limited ("MECO"), collectively referred to as the HECO Utilities.

DG/CHP and the Transmission and Distribution Planning Process

Q. Issue No. 11 in the instant docket states "What revisions should be made to the integrated resource planning process?" What is the HECO Utilities' position on this issue?

A. As stated in the direct testimony of Mr. Sakuda in HECO T-3, page 12, lines 13 to 16, the HECO Utilities' position is that no changes to the IRP Framework are required for consideration of DG and a significant effort is being made to consider DG and CHP technologies and their potential contribution to meeting the electrical needs of customers in the current round of integrated resource planning for HECO (IRP-3). In HECO RT-3, page 11, Mr. Sakuda states that DG/CHP will be evaluated within the overall IRP process, in the generation capacity planning and transmission planning process, to the extent practical. Mr. Sakuda will address DG/CHP considerations in the IRP process for generation capacity planning in HECO RT-3. My rebuttal testimony will address consideration of DG/CHP within IRP from the transmission planning perspective. In addition, my rebuttal testimony will address why 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, which will be explained later in my testimony.

DG/CHP in Transmission Planning

Q. How will DG/CHP be considered in the transmission planning process?

A. DG/CHP will be considered in the transmission planning process on a system wide basis. First, HECO will utilize the Long-Term Sales and Peak Forecast, which is not area specific, to determine yearly load growth rates. The yearly growth rates include DG/CHP estimates (as well as demand-side management ("DSM") estimates), and these growth rates are applied to a historical load distribution at the transmission level to determine forecasted load distributions. Second, because the magnitude and direction of the flow of electricity over the various transmission lines is heavily dependent upon where the electricity is generated, assumptions must be made as to the specific locations, sizes and operating costs of future central generating units (which also include as-available renewable generation). Third, given the locations and characteristics of existing generating units and transmission lines and the assumptions for future generating units (both location specific central station generators and DG/CHP allocated based on a historical load distribution), computer simulations are performed to determine the magnitude and direction of the flow of electricity over the various transmission lines. (These are called "load flow" calculations.) Fourth, the computer simulation results are compared against HECO's transmission planning criteria to determine where and when planning criteria violations, if any, are forecasted to occur. In addition, reliability concerns can be identified. Fifth, if any planning criteria violations or other significant reliability concerns (i.e., transmission problems) are identified, then possible solutions are evaluated.

Q. What are the possible solutions to address the identified transmission problems?

A. The possible solutions fall into two categories as explained in HECO T-4, pages 7-8. The first category of potential solutions to be studied covers the addition or modification of transmission and distribution ("T&D") facilities. These potential solutions include 1) increasing the capacity of the T&D system through the addition of new transmission lines, reconductoring existing transmission lines with conductors of higher capacity, or re-rating existing lines (through techniques such as dynamic line rating), 2) reconfiguring distribution or sub-transmission lines, which reallocate loads and changes the current flow across different transmission lines, 3) adding var sources such as capacitors on the transmission system, and/or (4) adding transformer capacity on the sub-transmission and/or distribution system.

The second category includes load reduction solutions. These potential solutions seek to reduce the amount of current that must travel through the particular transmission circuit. This can be done in two ways. One is by reducing the demand in the area served by the circuit through the implementation of DSM programs in the specific geographic area. The other way is to install generating sources, such as DG or CHP, in the area. There are practical issues with either approach, which are studied on a case-specific basis.

Q. What types of DG would be required to defer or resolve transmission planning criteria violations or reliability concerns?

A. As explained in HECO T-4, pages 14-15, T&D planning for the HECO/MECO/HELCO systems is based on peak load forecasts under various contingency conditions. If DG installations at customer sites are off-line, the utility will still be required to install facilities to serve the entire load and DG would not defer or address the T&D criteria violations or reliability concerns. Therefore, specific types of DG technologies that are firm will be required in most situations to defer T&D facility installations. Multiple DG installations may create diversity that could defer T&D facility installations. Specific analyses has not been conducted to determine the number and/or the size of DG facilities, which would create the diversity, however the concept of creating diversity was explained in HECO T-4, pages 14-15. There would also be issues with the control over the DG/CHP units. In the case of utility-owned facilities, the Company has direct control over how the facility is operated, maintained and integrated into the coordination of T&D system maintenance activities. For third-party facilities, there would need to be requirements and/or penalties in the purchased power contract to control the facility. In the case of the Hana DG installation, the reliability issue with the loss of the sub-transmission line to Hana Substation was addressed by relocating existing generation at the Lanai City Power Plant, which was scheduled to be retired, to the Hana Substation, which provided a relatively low cost option to address the Hana Substation reliability concern. In addition, the

Hana generators are owned and operated by MECO, which has direct control over the operation and the maintenance of the Hana generators.

Q. Are there difficulties in considering DG/CHP in the transmission planning analysis done as part of the IRP process?

A. Yes. Without assumptions for the specific locations of the generating sources, the load flow simulations cannot be performed. The supply-side resources in the HECO IRP-2 long-term resource plans did not identify site-specific firm generators and includes possible site locations for as-available and renewable generation. A transmission analysis to determine system transmission needs was not performed for the long-term resource plans although transmission and distribution interconnection costs were included in the unit information sheets (UIF) for the generators. Interconnection costs include items such as step-up transformers, generator tie lines, generator relaying, etc. In addition, a transmission and distribution study was conducted to determine a calculated transmission and distribution benefit from installing load reduction programs.

Performing the load flow simulations is a very complex and lengthy undertaking, even for a single assumption for the timing, size and location of future generating units. Single contingency outage scenarios for HECO/MECO/HELCO and double contingency outage scenarios for HECO must be considered in order to determine whether or not planning criteria violations will occur in any particular scenario. In IRP, numerous possible resource plans can be generated through the resource optimization process. Even though these possible resource plans are narrowed to a smaller set (less than two dozen plans), sensitivities are run to determine the impact on unit selection and timing of different sales and peak forecasts, different fuel price forecasts, different DSM and CHP program size, and other parameters. This multiplies the number of scenarios that must be assessed.

Furthermore, for the DG/CHP units, particular sites may be identified. But because the timing of installation is driven primarily by the customer, there is much uncertainty as to when the units will be installed. (See HECO T-4, page 15, line 9 through line 23.) Hypothetically, DG/CHP units can be incorporated into the IRP process in several ways, such as 1) using area specific DG/CHP assumptions, in which case transmission planning scenarios would have to either evaluate a large number of scenarios (i.e. low, base, high forecast, various central station generation scenarios, single and/or double transmission line contingency analysis, and various location and sizes of DG/CHP locations), would require an excessive amount of time for the analysis and introduces a high degree of uncertainty with respect to whether actual levels of DG/CHP can be achieved in specific areas, 2) using area specific DG/CHP assumptions and selecting several scenarios to evaluate, which would reduce the amount of time for the analyses, but would still have a high degree of uncertainty, or 3) using DG/CHP forecasts on a system wide level and allocating the impacts based on the methodology described earlier in my testimony for the transmission planning process.

Q. How were these difficulties addressed in HELCO and MECO's IRP-2?

A. HELCO's IRP-2 and MECO's IRP-2 reports, filed with the Commission subsequent to the HECO IRP-2 report on September 1, 1998 and May 30, 2000, respectively, included site specific assumptions for firm generating units. Transmission analysis for a few finalist plans with identified locations for the generating units was performed. The transmission analysis identified transmission capital projects, cost estimates for the transmission capital project and transmission system losses in addition to the interconnection costs, which were identified in the UIF. All of these costs were incorporated into the finalist plans.

DG was considered in the supply-side analysis for the HELCO IRP-2, which concluded that costs and benefits of DG are highly sensitive to the site and case under consideration, and although DG has the potential to be cost-effective, further study is warranted. The transmission analysis for HELCO IRP-2 did not consider impacts to the transmission system from DG/CHP installations.

DG was considered in the supply-side analysis for the MECO IRP-2 analysis, however it was concluded that MECO should handle DG on a case-by-case basis, since technology and assumptions can vary substantially. The transmission analysis for MECO IRP-2 did not consider impacts to the transmission system from DG/CHP installations.

Q. How will these difficulties be addressed in HECO's IRP-3?

A. In HECO IRP-3, location assumptions for firm generators will be made in order to perform a transmission analysis. In addition, the basic steps I outlined on page 2, line 12 through page 4, line 3 for incorporating DG/CHP in the transmission analysis for HECO IRP-3 will be followed. HECO will select a few (two or three) 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. The timing and location of transmission planning criteria violations will be identified, and the effectiveness of some possible solutions will be evaluated. Since the transmission analysis will also consider DG/CHP in the analysis, the evaluated solutions will include mainly transmission system upgrades or additions. In addition, if transmission constraints are identified as a result of the transmission analysis for the IRP processes, additional detailed studies would have to 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. An example of a detailed study was filed in Docket No. 03-0417 (East Oahu Transmission Project), Exhibit 5 and Exhibit 6.

DG/CHP in Distribution Planning

Q. How will DG/CHP be considered in the distribution planning process?

A. As in the transmission planning process, DG/CHP will be considered in the distribution planning process through a series of orderly steps, but with some significant differences. Like the transmission planning process, the distribution planning process starts with a forecast of demand. However, because distribution planning involves smaller geographical areas compared to transmission planning, the demand forecast for small geographic areas is based on historical demand, actual load data from distribution substation transformers, and current readings from each individual distribution line. Growth rates are applied to the historical demand, load data from distribution substation transformers and distribution line readings to forecast load demand on the distribution system. Growth rates are based on a historical trend of load demand and will include near-term DG/CHP projects. Load growth is dependent on customer project developments and can be attributed to the addition of new customers or increases in demand from existing customers. Since customers make the decisions as to what and when they will build, demand forecasts for these small geographical areas will vary depending on the progress of the project and load forecasts for distribution planning are updated on a regular basis as a result of project developments. Therefore load forecasts for the distribution system cannot be made further than three to five years into the future.

Next, given the assumptions for future demand, load flows on the distribution system can be calculated for radial distribution systems. In some instances computer simulations are performed to determine the magnitude and direction of the flow of electricity over the various distribution lines (i.e. distribution network systems). The calculated load flows and/or simulated load flows are compared against HECO's distribution planning criteria to determine where and when planning criteria violations, if any, are forecasted to occur. Finally, if any planning criteria violations are identified, then possible solutions are evaluated.

Q. What are the possible solutions to remove planning criteria violations?

A. The same categories of solutions I described in the transmission planning analysis, which include 1) additions or modifications to the distribution system and 2) load reduction options, apply to the distribution planning process on a case-by-case basis.

Q. Are there difficulties in considering DG/CHP in the distribution planning analysis in IRP?

A. Yes. As explained during the April 23, 2004 IRP-3 Integration Technical Committee Meeting and as stated earlier, part of the load forecast for distribution planning purposes incorporates actual load demand from distribution substation transformers and readings from individual distribution lines. A growth rate for the distribution substations is applied to the actual load demands at the substations. Load growth rates for the distribution system will be different for different areas and are not based on the IRP 20-year sales and peak forecasts. Load growth is dependent on customer project developments (new customers or existing customers) and will vary depending on the progress of the project and therefore cannot be forecasted more than three to five years into the future because such load growth depends so much on customer decisions over which HECO has no control. It would be difficult to integrate distribution planning into the long-term IRP analysis. A copy of the presentation at the April 23, 2004 IRP Integration Technical Meeting is attached as HECO-R-400. As an example, in Docket No. 7526, filed on November 12, 1992, HECO proposed a project to install the Kewalo A&B 30/40/50 MVA transformers, two underground 138kV transmission lines, two 25kV underground distribution lines, fiber optic cable and associated work to increase the capacity required to relieve projected distribution overloads and to provide capacity for future load growth in the Kakaako area. At the time of the application, overloads were projected to occur in 1993 and the service date for the project was December 2004. The project was approved by the Commission in Decision and Order No. 12616 on September 23, 1993. On January 25, 1996, HECO informed the Commission that the service date for the Kewalo transformers and the 138kV transmission line was deferred due to lower load forecasts for the Kakaako area than when the application was prepared. In Docket 7602, filed on February 10, 1993, HECO proposed a project to install the Kewalo-Kamoku 138kV transmission line, which was the second phase of the Archer to

Pukele 138kV line and would also make provisions for the Kamoku Substation to accommodate future load growth. The project was approved by the Commission in Decision and Order No. 12627 on September 24, 1993. On January 25, 1996, HECO informed the Commission that the service date for the Kewalo-Kamoku 138kV transmission line was deferred from a service date between 1995-1997 to May 1999 because of lower load forecasts for the area than when the application was prepared.

Furthermore, when considering DG/CHP units, particular sites may be identified, but because the timing of installation is driven primarily by the customer, there is much uncertainty as to when the units will be installed. (See HECO T-4, page 15.) Without knowing the timing of the installation of the DG/CHP units, the distribution planning scenarios would have a high degree of uncertainty.

Q. How will these difficulties be addressed in HECO's IRP-3?

A. 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 presentation given at the April 23, 2004 IRP Technical Committee Meeting explained that 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.

<u>Determining DG Locations</u>

Q. Please explain what is meant by DG locations?

A. In HREA-T-1, page 12 Mr. Bollmeier suggests that the utility, through the IRP process, 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." The Consumer Advocate defined and termed similar information as identified "load pockets." (See CA-T-1, page 13-14)

Q. Would the utility be able to identify the load pocket information in the context of the IRP process?

A. 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 <u>not</u> 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.

Q. Please explain the difference between transmission constraints for load demand compared to generation unit additions.

A. An increase in load demand will affect how the power flows through the system. In general, as the load increases, the power flowing through the transmission path that is serving this load will increase and in some cases can cause a transmission constraint such as a line overload or a low voltage situation. Theoretically, DG/CHP can address the transmission constraint if the amount of DG/CHP installed is equal to the forecasted yearly load growth. For transmission constraints triggered by generation unit additions, the transmission constraints occurs when the generating unit is installed and will remain the same and not continue to grow unless additional generation is installed or the operation of the unit is changed (i.e. baseload versus a peaking unit). HECO utilizes economic dispatch when performing load flow analyses, therefore a peaking unit may not be at full output compared to a baseload unit, which may have lower costing energy compared to the peaking unit and therefore will be dispatched at a high level of output.

Q. Describe the practical issues associated with installing substantial amounts of area-specific DG/CHP on the system.

A. Practical issues with DG was explained in HECO T-4, pages 11-13 which include the availability of land in the area of installation required to mitigate the identified transmission constraints, 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. In addition, as stated in HECO T-4, page 15, DG/CHP at customer sites cannot be fully controlled by the utility, because customers may have other criteria in mind when they determine whether to install DG on-site or CHP, which may not necessarily coincide with the utilities need to resolve transmission constraints. If the calculated amount of DG/CHP is not achieved, if load growth in the specific geographic area identified increases at a higher rate than forecasted, the transmission constraint would occur and could affect the reliability of electricity service to customers. Resolving the transmission constraint by upgrading the existing transmission system cannot occur instantly and requires time to implement. Therefore, HECO plans to utilize its existing transmission planning methodology of incorporating DG/CHP impacts on a system-wide basis. Incorporating DG/CHP impacts on a system-wide basis can address some of the uncertainties of DG/CHP, can estimate the overall impact of CHP/DG on transmission requirements to some extent, and can identify larger geographic areas where DG/CHP (in addition to what is included in the forecast) may be of more value. DG/CHP that are actually installed on the system will be incorporated into the analysis through the yearly benchmark of the model as explained in HECO T-4, page 6.

SUMMARY

Q. Please summarize your testimony.

A. With respect to DG/CHP in IRP, no changes to the IRP Framework are required for consideration of DG (which includes CHP). DG/CHP will be considered in the IRP process from the generation capacity planning and transmission planning perspectives to the extent practical and DG/CHP will continue to be evaluated on a case-by-case basis in the distribution planning process. 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. The IRP process already identifies certain geographic areas where DG may be able to provide the most benefit, and 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 as proposed in the methodology described on pages 2-3.

Q. Does this conclude your testimony?

A. Yes, it does.