HREA-HECO-T-1-IR-1

On page 7 (line 5) and page (line 15), you introduce the term "short term." How do you define "short term?"

<u>HECO Response:</u>

As stated in the response to TGC/HECO-SOP-IR-5, "short term" generally would be in the one to seven year time horizon.

HREA-HECO-T-1-IR-2.

On page 8 (lines 24 – 25), do you agree with HREA's position that the customers will determine whether a form of DG is "feasible and viable" for Hawaii?

HECO Response:

Customers will determine whether a form of DG is "feasible and viable" with respect to customer-sited and customer-owned generation, as stated on lines 21-25. Ultimately it will be the developer of the DG that determines feasibility and viability, whether it is a customer, the utility, or a third-party developer.

HREA-HECO-T-1-IR-3

On page 9 (line 15), has HECO looked at quantifying the distributed benefits of wind turbines and photovoltaics?

HECO Response:

No. HECO has not conducted any such analysis.

HREA-HECO-T-1-IR-4

On page 11 (line 11+), aren't there also negative economic impacts associated with our continued use of fossil fuels, e.g., negative impacts of exporting our dollars for foreign oil and coal?

HECO Response:

There are negative economic impacts to the degree any dollars are "exported" outside our local economy whether it be for fuel, services, or equipment. This applies to all forms of energy production, both fossil fuel and renewable. It is disingenuous to focus on only one aspect – fuel cost – when considering economic impacts of energy production alternatives. As an example, comparing a fossil fuel generator with a photovoltaic system, both systems are manufactured outside of Hawaii and so one can consider the equipment dollars to be exported. Yet on a cost per kilowatt-hour basis, the fossil fuel generator is cheaper than the photovoltaic system and one could argue that therefore, fewer dollars are being exported using the fossil fuel system.

HREA-HECO-T-1-IR-5

On page 11 (lines 12 – 13), would it not be more correct to say that there have been some negative externalities (aesthetics, noise and bird strikes) associated with the early applications of windpower in California in the 1980's and that the impacts are site-specific by their nature? Since then, would you agree that industry has worked hard with all stakeholders to mitigate concerns about negative impacts on a project-by-project basis?

HECO Response:

The discussion in HECO T-1 provides a description of the positive and negative aspects of generating technologies in a general sense. Although industry may have worked hard to mitigate concerns, the fact remains that wind developers must still be sensitive to aesthetic impacts, noise, and bird strikes simply because of the nature of the technology.

HREA-HECO-T-1-IR-6

On page 16 (lines 10 – 16) and page 18 (lines 24 -25, would not there be rate impacts due to utility DG investments?

HECO Response:

There would be rate impacts, however, the Companies' economic analyses that were filed in its CHP Program application in Docket No. 03-0366 showed that these impacts are preferable from the standpoint of all ratepayers when compared to the significant adverse rate impacts that can result from the loss of sales to third party or customer owned DG.

HREA-HECO-T-1-IR-7 **(NOTE: HREA submitted two HREA-HECO-T-1-IR-6. HECO renamed this IR to HREA-HECO-T-1-IR-7)**

On page 16 (lines 3 – 16), you state the "Development of the CHP market may generate enough capacity to help defer the need for new central station generation." However, if HECO is allowed to rate-base CHP investments, and, if it turns out that the CHP doesn't defer the need for new central station generation (CG), wouldn't the ratepayers have to pay twice for the same capacity?

HECO Response:

The CHP generation would not be the same as the central station generation. Even if a CHP system hypothetically did not help to defer new central station generation in and of itself, there would still be overall ratepayer benefits if the utility does the CHP as opposed to a non-utility entity because of the retained revenues and contributions to fixed costs. If no deferral benefit is realized by the CHP, the scenarios to compare are (1) a non-utility entity develops the CHP, followed by the utility installing a central station generating plant, and (2) the utility develops the CHP, followed by the utility installing a central station generating plant. The latter scenario is preferable from the ratepayer perspective. In the case of HECO, new generation is needed in 2006 (even with the proposed CHP Program), but is projected to be installed in or about 2009. Thus, the CHP systems installed by HECO are already needed for capacity purposes.

Finally, the need for future capacity must be based on forecasts. Central station generation requires long lead times, and there may be uncertainty regarding the in-service date for new generation. One of the benefits of DG/CHP is that it can be installed in smaller increments, and can be used to help address some of the uncertainty inherent in forecasts and adding new generation.

HREA-HECO-T-1-IR-8

On page 19 (lines 11 – 13), what does the phrase "so that non-participating customers are not burdened" mean?

HECO Response:

Non-participating customers are the customers of the utility other than the host CHP customer. The Companies' proposed CHP Program is structured so that from a rate impact standpoint, non-participating customers are better off when a host CHP customer chooses to do CHP with the utility rather than a non-utility CHP provider. In this manner, non-participating customers are not burdened by the Companies' proposed CHP Program.

HREA-HECO-T-1-IR-9

On page 19 (lines 24 – 25) and page 20 (lines 1 – 5), you discuss the issues of operation and maintenance of CHP by a 3rd party, and ensuring that the CHP contributes to the reliability and safety of the grid. If the interconnect agreement of the CHP with HECO included provisions to ensure reliable services, how would that be different from a Power Purchase Agreement (PPA) that binds an Independent Power Producer (IPP) to provide power to a prescribed schedule? HECO doesn't appear to have any trouble integrating its purchased power, which, incidentally, is about 24% of its sales.

HECO Response:

An interconnection agreement and interconnection standards seek to protect the utility grid and customer equipment, as opposed to a purchase power agreement ("PPA"), which governs the operating performance of a non-utility generator in providing power to the utility. An IPP that seeks to export power to the utility grid for sale must obtain both a PPA and an interconnection agreement from the utility.

HREA-HECO-T-1-IR-10

On page 20 (line 9), you indicate that there is one other utility (Austin Energy, Austin, Texas) that offers utility-owned, operated and maintained CHP. How many CHP systems have they installed? Are they allowed to rate-base their investments? Are they allowed to pass through their fuel costs to their customers?

HECO Response:

Please see the response to LOL-WDT-IR-31 for the information that HECO has been able to obtain on the Austin Energy CHP/DG program.

HREA-HECO-T-1-IR-11

On page 21 (lines 1 – 6), you introduce the possibility for conflicting objectives between regulated and unregulated businesses of the Companies, which would not be present if the Companies provided CHP systems services on a regulated basis. Is this really a valid concern, given that HECO has already had two unregulated companies in the wholesale power or DG business in Hawaii, i.e., Hawaii Electric Renewable Systems (HERS), as a windfarm developer/operator and Provision, as a supplier of PV systems? If this is a valid concern, please explain.

HECO Response:

It is a valid concern primarily because the CHP customer base is directly the same as that of the electric utility, as opposed to the HERS and Provision cases. In the case of HERS, this entity was a wholly owned subsidiary of Hawaiian Electric Industries, Inc., the parent corporation of HECO. HERS' focus was on developing renewable energy projects, primarily wind farms, in Hawaii. HERS' business model was for the company to develop or acquire wind farms, then sell the power to the electric utility via purchase power agreements. HERS' direct customer was the electric utility itself, not the utility's customers. With Provision, the focus was on providing off-grid photovoltaic power systems. To the extent that Provision's customers were off-grid, Provision's customers differed from the utility's.

HREA-HECO-T-1-IR-12

On page 22 (lines 5 - 6), you state that a threshold of 400 kWs was established for possible CHP applications. Is it correct to say that 400 kW is a threshold for HECO, if HECO were to install, own and operate the CHP systems? Consequently, would you agree that 3rd party DG providers may have a lower threshold?

HECO Response:

No. 400 kW is not a threshold for HECO. As stated in HECO T-1, projects below about 200 to 250 kW would generally not be economical, however project economics are affected by site-specific factors. Third party DG providers may certainly have a threshold that is different from that of the utility.

HREA-HECO-T-1-IR-13

On page 24 (lines 16 -20), how extensive was HECO's survey of customers? Was it only with customers that have loads of 400 kW and above?

HECO Response:

HECO did not conduct an extensive survey of customers but has had numerous customer contacts concerning CHP primarily as a result of presenting information about the utility's proposed CHP program at broad discussion forums. These customers represent a range of commercial and institutional customers, some of whom have loads lower than 400 kW.

HREA-HECO-T-1-IR-14

On page 25 (lines 9 – 11), is your statement the utilities' involvement in the CHP market would provide more choices and options based on the assumption that no 3rd parties would or could offer similar products and services?

<u>HECO Response:</u>

The Companies are making no assumptions about whether third parties would or could offer similar products and services as the utility. Allowing the utility to offer CHP to customers provides additional choices and options regardless of what third parties offer.

HREA-HECO-T-1-IR-15

On page 26 (line 19), you note that HECO has selected a contract term of 20 years. Is this really practical, given that customers may not be willing to sign contracts beyond 5 to 7 years, and that with the evolving state of the technology, it does not appear to make sense for either customers or HECO to limit their options for the future?

HECO Response:

HECO is currently developing several CHP projects with customers and all are willing to sign a 20-year contract. The utility's focus is on working with customers who, like the utility, are concerned about long-term stability and place value on longer-term contracts, which help to defer the need for central station generation, which has 30-50 year lives. There will certainly be customers who prefer not to sign long-term contracts, and the utility's proposed program will not be a fit for them. A key provision of the CHP Agreement proposed in the Companies' CHP Program is that the utility will be responsible for operation, maintenance, and replacement of the CHP equipment throughout the term of the CHP Agreement. To the extent that new technology can be integrated in a cost-effective manner without degrading CHP system performance, the utility will be able to capitalize on technology advances.

HREA-HECO-T-1-IR-16

On page 29 (lines 3–5), what is the limit (in kW) of DG installation that would be covered under Tariff Rule 14.H?

HECO Response:

There is no kW limit established in Rule 14.H for DG.

HREA-HECO-T-1-IR-17

On page 33 (line 15), please provide a list of the Hess projects and the approximate amount of savings to the customer in each case.

HECO Response:

The Companies are aware of the following Hess CHP installations:

Pohai Nani Good Samaritan Retirement Community (Oahu)
Hale Pauahi (Oahu)
Fort Shafter (Oahu)
Honolulu Hale (Oahu)
Fairmont Orchid (Big Island)
Regency at Hualalai (Big Island)
University of the Nations (Big Island)
Maui Customer (The customer name is confidential.)

The Companies do not have information on customer savings as the projects are non-utility projects.

HREA-HECO-T-1-IR-19

On page 34 (lines 14 – 21), it would appear that the customer would be paying for backup or premium power. Therefore, is this really an example of an externality, i.e., a cost that is not covered in the transaction?

HECO Response:

To the degree that backup or premium power is given a valuation and the customer is paying for it, it would not be considered a "true externality".

HREA-HECO-T-1-IR-20

Similarly on page 35 (lines 5 to 7), it would appear that the customer would benefit directly via lower initial costs for newer technologies. Therefore, is this really an example of an externality, i.e., a cost that is not covered in the transaction?

HECO Response:

The point is that the smaller scale of DG provides added flexibility to the utility or customer.

Flexibility would not necessarily be given a valuation in a transaction.

HREA-HECO-T-1-IR-21

Overall, why are you referring to DG and CHP or DG/CHP, when CHP is a type of DG?

HECO Response:

The Companies want to emphasize this focus on CHP, which is distinct from many other forms of DG. For example, the Companies are proposing a CHP Program, not a generic DG program.

HREA-HECO-T-1-IR-22

Overall, of all the possible DG, is HECO really only interested in CHP, and, actually only specific applications of CHP?

HECO Response:

Of all the DG technologies, HECO's programmatic focus is on CHP, although the Company plans to use other forms of DG on a case-by-case basis as described on pages 13 and 14 of HECO T-1. The CHP that is of interest are those projects that are effective in terms of providing benefit to both the CHP host customer and the broader ratepayers and system. The utility is generally not interested in pursuing CHP where it does not fit the parameters of its proposed CHP Program.

HREA-HECO-T-2-IR-1

On page 2 (line 21), why didn't you mention the experience of ProVision Technologies, Inc with PV?

HECO Response:

HECO is not affiliated with ProVision Technologies, Inc., a former subsidiary of Hawaiian Electric Industries, Inc., HECO's parent company.

HREA-HECO-T-2-IR-2

On page 4 (line 20), were these costs that HECO paid to contractors for the installations?

HECO Response:

The cost range indicated in HECO T-2, page 4, are estimates of installed costs for PV installations in Hawaii. This range is also based on installed costs for grid-connected 2-kW PV systems installed at public schools on Oahu as part of HECO's Sun Power for Schools program.

HREA-HECO-T-2-IR-3

On page 14 (line 10), would you agree that the experience in Hawaii has shown that windfarms can and provide power during peak periods?

HECO Response:

From the utilities' perspective, the peak period encompasses the period from 7:00 am to 9:00 pm, with the 7:00 am to 5:00 pm period called the shoulder peak and the 5:00 pm to 9:00 pm period called the priority peak. As long as windfarms are operational and connected to a utility's grid, they can and do provide energy as it is available to the grid during the 14-hour peak period.

It should be noted that although windfarms can provide energy during the peak period, sellers of energy to the electric utility from as-available resources such as windfarms are under no obligation to deliver scheduled amounts of power at particular levels upon demand by the utility. In Decision and Order No. 18568, dated May 30, 2001, Docket No. 00-0135 (Apollo Energy Corporation Petition), Section III.A., page 4, the Commission stated, "The wind resource used by Apollo to generate energy is as-available. The generation of energy by wind farms such as Apollo is ultimately dependent upon the availability and strength of this resource. Apollo, the commission finds, is not under a continual obligation to supply power to HELCO upon demand."

HREA-HECO-T-2-IR-4

On page 15 (line 15), were you aware that the wind industry definition of small wind turbines is 100 kW and under?

HECO Response:

HECO is aware that small-scale wind turbines are defined to be up to 100 kW by the American Wind Energy Association ("AWEA"), between 20 W to 100 kW by the U.S. Department of Energy, 50 kW or less by the National Wind Technology Center, and between 1 kW to 50 kW by the California Energy Commission ("CEC").

HREA-HECO-T-2-IR-5

On page 16 (line 7), would you agree that height restrictions will be an issue throughout the islands, such that a wind user will need to seek a zoning variance?

HECO Response:

Depending on the location and County, height and other restrictions may need to seek a zoning variance. According to Sec. 21-5.700 of the Land Use Ordinance ("LUO") of the City and County of Honolulu, "All wind machines shall be set back from all property lines a minimum distance equal to the height of the system. Height shall include the height of the tower and the farthest vertical extension of the wind machine." In addition, Sec. 21-4.60 of the LUO specifies that wind machines shall be exempt from zoning district height limits under specified restrictions, specifically "Wind machines, where permitted, provided that each machine shall be set back from all property lines one foot for each foot of height, measured from the highest vertical extension of the system." Persons or entities planning to install wind turbines must investigate applicable permits and land use variance requirements. Land use provisions for other Counties in the State may vary.

HREA-HECO-T-2-IR-6

On page 18 (line 22), were you aware that there are a number of turbines manufactured in the U. S. ranging in capacity from 300 watts (Southwest Windpower to 50 kW (Bergey and Atlantic Orient) and 100 kW (Northern Power Systems)?

HECO Response:

HECO is aware that wind turbines less than 10 kW and greater than 30 kW are manufactured.

HECO has collected material on several small wind turbines and used the Bergey 10 kW and Fuhrlander 30 kW machines as examples in its direct testimony.

HREA-HECO-T-2-IR-7

On page 20 (line 9), what is your definition of long-term?

HECO Response:

Long-term would be in the ten-year and greater time horizon.

HREA-HECO-T-2-IR-8

On page 21 (line 8), why did you not mention the 340 MW of solar thermal electric (STE) that is installed and operating at Kramer Junction, CA, and that Solargenix is under contract to install a 50 MW state-of-the-art STE system in Nevada?

HECO Response:

HECO is aware of the solar thermal electric installations at Kramer Junction, CA with a collective capacity of 354 MW, which were installed between 1985 and 1991. Luz, the developer of these systems, went bankrupt after the federal government failed to extend the solar tax credit. No other solar thermal electric systems have been installed in the United States since then.

In 1992, the state Department of Business, Economic Development and Tourism, subcontracted with an ex-Luz engineer to conduct a study entitled, "Solar Electric Generating System ("SEGS") Assessment for Hawaii. In general, this study concluded that "the principal reasons for the unfavorable economic results are the higher capital costs and lower system performance projected for SEGS plants in Hawaii…."

HECO also is aware of the 50 MW Solargenix solar thermal system proposed for Nevada. It is our understanding that the 50 MW Solargenix project has been delayed at least until January 2005 due to difficulties in finalizing financing arrangements.

HREA-HECO-T-2-IR-9

On page 21 (line 13), are you aware that solar air conditioning systems are commercially-available from Solargenix on the mainland and there is a lake water air conditioning system (similar in concept to seawater air conditioning) at Cornell University in New York state.

HECO Response:

HECO is aware that Solargenix offers solar-based cooling products; however, the commercial viability of these products is uncertain. In addition, information about Solargenix's solar-based cooling products is limited.

HECO also is aware of the lake water air conditioning system located at Cornell University.

HREA-HECO-T-2-IR-10

On page 21 (line 15), would it not be more correct to say that grid-connected PV is not economically viable today without incentives, such as tax credits and net energy metering?

HECO Response:

The testimony is correct. HECO does acknowledge that tax credits and net energy metering can help reduce the costs of grid-connected PV systems.

HREA-HECO-T-3-IR-1

On page 10 (line 4 - 6), please explain why you have concluded that some 3rd party CHP installations would not be as reliable as utility-owned CHP?

HECO Response:

As examples, (1) some CHP systems that are installed by third parties may be of substandard design or construction; (2) some CHP installations may be operated and maintained by third parties who lack adequate operating and maintenance training or experience; and (3) some CHP systems that are owned, operated and maintained by customers themselves may not be properly or adequately maintained because power generation may not be within the customer's core expertise. This is in contrast to CHP systems that are installed, operated and maintained by the utilities, whose core business is power generation and who have substantial power generation experience.

HREA-HECO-T-3-IR-2

On pages 11 and 12, you emphasize the potential rate impacts due to loss revenues from installation of non-utility DG. Would not there also be potential rate impacts due to utility investments that would be rate-based? Have you compared the potential rate impacts for both cases in detail, i.e., non-utility vs. utility owned DG?

<u>HECO Response:</u>

In a case where the utility loses revenues as a result of the installation of third party DG, the utility would lose some of the contributions to fixed costs that were covered by the lost revenues. In order to recover the lost contributions to fixed costs, all other factors being equal, rates for remaining customers would need to be increased.

In a case where new central station generation is installed, rates could increase if the unit of cost of generation increases with the installation of the new unit.

In either case, there is the potential for the average ratepayer to experience a rate increase.

The utilities have performed cost effectiveness calculations as noted in HECO T-3, page 10, line 18, to page 12, line 7, and also in HECO T-1, page 16, line 23 to page 18, line 6, and page 19, lines 1 to 21.

HREA-HECO-T-3-IR-3

On page 12 (line 23), wouldn't it make sense to evaluate an aggregate forecast of DG in IRP in the same manner as you would evaluate a similar amount of demand-side and/or supply-side resources?

HECO Response:

HECO, HELCO and MECO already did this in their IRP-2 Evaluation Reports:

- In HECO's IRP-2 Evaluation Report, filed on December 31, 2002 in Docket No. 95-0347, HECO stated in Section 3.2.6 on page 43: "HECO has been actively monitoring DG developments in its service territory. Based on known current and proposed DG projects, HECO believes DG will play a role in reducing overall demand on the grid in the near and long term. This is reflected in HECO's August 2002 Sales and Peak Forecast, which assumes near- and long-term penetration of distributed generators to be about 1 MW per year. The result is a total DG penetration of 21 MW and a corresponding 21 MW reduction in peak demand over the forecast period."

- In HELCO's IRP-2 Evaluation Report, filed on March 31, 2004 in Docket No. 97-0349, HELCO provided in Section 3.2.2 on pages 25 to 27 the projected amount of non-utility CHP impacts on the HELCO system and the projected amount of utility-owned CHP installations on the HELCO system.

- In MECO's IRP-2 Evaluation Report, filed on April 30, 2004 in Docket No. 99-0004, MECO provided in Section 3.2.2 on pages 21 to 24 the projected amount of non-utility CHP impacts on the MECO system and the projected amount of utility-owned CHP installations on the MECO system.

HECO, HELCO and MECO intend to continue to reflect the aggregate forecast of DG and CHP in their respective IRP-3 major review. HECO's IRP-3 is currently in progress in Docket No. 03-0253 and is targeted for filing in March 2005, but 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. For HECO's plans with respect to its IRP-3 CHP evaluation, see HECO T-3, pages 13-14.

HREA-HECO-T-3-IR-4

On page 15–16, you raise a number of issues regarding use of emergency/back-up generators as part of the County of Maui's proposed Virtual Power Plant concept. However, doesn't it make sense to evaluate the County's proposal in more detail to determine of the existing units could be converted to provide capacity to MECO?

HECO Response:

HECO asked the County of Maui information requests on its Virtual Power Plant concept. HECO will await the County of Maui's responses to determine if the data provided is sufficient to further evaluate the County of Maui's proposal of the Virtual Power Plant concept, and/or HECO will seek additional information through Supplemental Information Requests, Rebuttal Information Requests or at the evidentiary hearing, if there is one.

HREA-HECO-T-3-IR-5

On pages 16 – 17, you discuss detailed requirements that Independent Power Producers must meet. Couldn't these requirements also be placed on CHP producers to convert existing generators to the County's Virtual Power Plant concept?

HECO Response:

While owners of existing emergency generators could voluntarily choose to accept the type of performance and reliability standards along with the penalties for non-delivery or sub-standard performance as described in the referenced testimony, the utilities would not be able to unilaterally force these owners to accept these provisions. It seems unlikely to the utilities that owner's of emergency generators would voluntarily accept these types of provisions given that the emergency generators are installed for a purpose other than serving the utility grid's needs and that the owners would take on risks they do not now incur.

HREA-HECO-T-3-IR-6

On page 18 (lines 19 – 20, why don't MECO and HELCO have spinning reserve policies?

HECO Response:

HELCO does not carry spinning reserve because of the high cost associated with doing so. HELCO analyzed the spinning reserve issue in depth in its IRP-2 report[1], Section 5.3.2. HELCO found that carrying spinning reserve increases production costs substantially. The study found that the increase in present value revenue requirements for fuel and variable O&M costs over the 20-year planning period was $22.6 million to carry enough spinning reserve to cover the loss of the largest unit on the system (PGV at 30 MW)[2]. HELCO concluded that it is "reluctant to incur the additional costs of maintaining spinning reserve, realizing that this would simply mean a higher cost of electricity to its customers."[3]

MECO does not carry spinning reserve because of similar concerns about cost. MECO has not performed any detailed analysis on the cost of providing spinning reserve.

[1] Filed with the PUC on September 1, 1998, in Docket No. 97-0349.
[2] HELCO IRP-2 report, Table 5-2, page 5-5.
[3] Ibid., page 5-5.

HREA-HECO-T-3-IR-7

On page 19 (line 22 -23), would it not be more correct to say that wind turbines, PV, and as-available hydro, can provide capacity and energy upon demand a portion of the time? Consequently, would it not be appropriate to conduct a statistical analysis to determine the coincidence of the as-available sources (individually and in aggregate) to provide reserve capacity? Given this analysis, could you not then determine the amount of additional reserve capacity that would be needed, or whether shortfalls from the as-available sources could be covered by spinning reserve?

HECO Response:

Please refer to HECO's responses to COM-HECO-DT-IR-15 and HREA-HECO-T-2-IR-3.

HREA-HECO-T-4-IR-1

Your testimony is very comprehensive and detailed. For the lay person, please explain how HECO Transmission and Distribution (T&D) planners identify the need for new T&D upgrades and enhancements, and how this planning activity might be used to identify market opportunities for DG.

HECO Response:

The Companies have a set of minimum guidelines for which the T&D systems are planned. These guidelines are called planning criteria and were provided in HECO 401-406. Using computer simulations to represent the T&D system, a look of how the T&D system will look like in the future (based on current planning assumptions) can be represented using these simulations. The simulations help identify planning criteria violations such as T&D line overloads or low voltage situations. In addition, there may be reliability concerns such as a loss of service to a heavily loaded substation, which can be identified. Planning criteria violations and reliability concerns will require solutions. As explained in HECO T-4, pages 7-17, both new and upgrades to the T&D facilities and non-T&D options are considered to address planning criteria violations and reliability concerns, including DG. HECO T-4, pages 9-17 considers various forms of DG and provides specific examples and the factors involved in considering DG to address the identified planning criteria violations or reliability concerns. As identified in HECO T-4, there are practical limitations on using targeted DG to address T&D needs. See, for example, HECO T-4, pages 13-17.

HREA-HECO-T-4-IR-2

As an example to your response to HREA-HECO-T-4-IR-1, would the transmission line overloads identified on page 12 (lines 8 to 11) suggest opportunities for DG. Please explain your answer.

HECO Response:

As stated in HECO T-4, page 8, DG in various forms are evaluated when line overload problems are identified. A transmission line study for HELCO's Keahole-Keamuku (6800) 69kV transmission line is currently being done and will include an evaluation of DG and its effectiveness to resolve the identified line overload. HECO T-4, page 12, lines 13-25 explains how the opportunity to use DG in the form of CHP was conducted for the Waimea-Keamuku (7200) and Waimea-Ouli (7300) 69kV line overload situations. Please also refer to the response provided in CA-SOP-IR-15.

HREA-HECO-T-4-IR-3

On page 13, you discuss customer-sited CHP, but also DG and CHP. Are you really only looking at CHP? Please explain your answer.

HECO Response:

HECO T-4, page 13, lines 13-25 explains how CHP is taken into consideration in T&D planning studies. HECO T-4, page 13 line 25 through page 17, line 5 discuss both DG and CHP systems.

HREA-HECO-T-4-IR-4

On page 16, would your concerns about 3rd party CHP facilities go away if operational and reliability issues were addressed in the interconnection agreements? Please explain your answer.

HECO Response:

Interconnection agreements address requirements that are needed in order for a facility to interconnect to the system and do not address performance and reliability standards for CHP facilities. Hypothetically, performance and reliability standards, such as those in purchase power agreements could be included in agreements between 3rd party CHP facilities and the utility, however it is unlikely that third-parties would enter into such agreements, and such agreements would not be as effective as having direct control over a facility. See the responses to HREA-HECO-T-3-IR-5 and COM-HECO-DT-IR-27.

HREA-HECO-T-4-IR-5

On page 17, if backup and/or emergency generators could be converted to operate to utility requirements, wouldn't that be a good option to evaluate in your T&D planning activity? Please explain your answer.

HECO Response:

Backup and/or emergency generators could be evaluated as part of T&D planning if they were available for use by the utility. HECO T-3, pages 15-16, lists several issues and concerns, which need to be resolved in order for utilities to rely on "virtual" backup power plants to provide reserve capacity for generation or for T&D planning activities. There may be ways to address these issues and concerns such as signing agreements with backup and/or emergency generator owners, which contain detailed requirements such as those explained in HECO T-3, pages 16-17, however, it seems unlikely to the utilities that owner's of emergency generators would voluntarily accept these types of provisions given that the emergency generators are installed for a purpose other than serving the utility grid's needs and that the owners would take on risks they do not now incur. See the response to HREA-HECO-T-3-IR-5.

HREA-HECO-T-4-IR-6

On page 25 (lines 28–29) and page 26, isn't it also possible that properly designed, installed and operated DG can provide voltage support? Please explain your answer.

HECO Response:

Yes, HECO recognized some of the positive impacts on power quality and reliability of DG in its Preliminary Statement of Position, page 20.

HREA-HECO-T-4-IR-7

On page 26 - 28, HREA is confused as to your position regarding islanding. Are you saying DG should disconnect during or ride through faults? Will this depend on the type of DG and its size? Please explain your answer.

HECO Response:

As stated in HECO T-4, page 25, the impact of DG facilities on the T&D power quality is very complex. Requirements for the reliable operation of the transmission system are different than for the reliable operation of the distribution system. One area is in how protection systems are designed and coordinated. On a small island-utility system such as HELCO and MECO, which mainly rely on quick-start diesels to address generating unit contingencies rather than carry spinning reserve, a high penetration of DG may be problematic in the area of undervoltage and underfrequency ride through. For example, a fault condition on the transmission system, which can be caused by conditions beyond the Company's control such as lightning strikes, fallen trees, or automobile accidents which damage a T&D line, could cause low voltage conditions. The low voltage conditions could cause the DG units to disconnect from the electric grid. A large disconnection of DG units from the utility system could cause an underfrequency load shedding event. However, when considering the distribution system, a DG unit with undervoltage ride through, which was not designed to regulate frequency or voltage, could cause frequency and/or voltage oscillations on the distribution circuit. These oscillations could have adverse impacts on customers' equipment served by the distribution circuit. Specifying if a DG unit should disconnect or ride through faults and other interconnection requirements (breaker interconnection schemes, voltage regulation capability, etc.) for DG units exporting on the T&D system should be studied on a case-by-case basis.

HREA-HECO-T-4-IR-8

On pages 28 to 29, you discuss Rule 14H. Is there a maximum size limit (in kW) for facilities under Rule 14H? Please explain your answer.

HECO Response:

There are no maximum size limits for facilities, however, there are varying degrees of technical analysis. Appendix III of Rule 14.H. describes the Interconnection Process which includes a technical review process.

HREA-HECO-T-5-IR-1

On page 2 (lines 15 – 16), marginal costs appear to be the same as avoided costs. Are they? Please explain your answer.

HECO Response:

Marginal costs are not the same as avoided costs. Marginal cost refers to the unit change in cost due to a unit change in output. As stated in HECO T-5 (pages 3-5), avoided costs are the incremental or additional costs to the utility of electric energy or firm capacity or both which costs the utility could avoid as a result of the installation of generation (e.g., avoided generation capital costs, avoided fixed operation and maintenance costs). For instance, 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. Both marginal cost and avoided cost measure changes in costs. However, the changes in costs reflected by the two measures are not the same, so that the two measures do not reflect the same costs. For instance, if the system load increases (or decreases) by 1 unit (e.g., 1 kW or 1 MW), the marginal generation cost is the unit increase (or decrease) in the utility's generation costs due to the unit increase (or decrease) in the system load to be served by the system. Avoided cost, on the other hand, refers to the difference between the total costs of serving the total system load (not only the unit change in the system load), and the total costs of serving the same total system load and incorporating the occurrence of some future event that impacts the system requirements to serve the load (e.g., installation of firm DG capacity).

HREA-HECO-T-5-IR-2

On pages 8 – 11, you discuss the overall approach to rate design. Why don't residential and small commercial customers have a demand charge?

HECO Response:

Demand charges require the installation of demand meters to meter the customers' kW load. In general the average kW load of the residential and small commercial customers are too small (5 kW to 6 kW per customer per month) to justify the additional cost of installing demand meters. While the cost of demand meters have been declining in recent years, the initial costs of replacing the existing kWh meters for all residential and small commercial customers would be significant.

HREA-HECO-T-5-IR-3

On page 12, you discuss the cross-subsidy of residential customers by commercial customers. Are there other cross-subsidies? Please explain.

HECO Response:

HECO-501 provides a summary of the cross-subsidies reflected in the HECO's, HELCO's, and MECO's 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.

HREA-HECO-T-5-IR-4

Would not charges for standby service (pages 17 – 19) be highly dependent on the type of DG facility and the interests of the DG owner/operator? For example, if the DG were operated continuously during peak periods, the DG owner/operator might only want standby service during routine maintenance and emergencies. Given that, would not it be reasonable to cover such downtime with the utility's operating and/or spinning reserve, and thus only charge the customer for the energy used?

HECO Response:

As discussed in HECO T-5, Page 11, beginning on Line 8, the Company's rate design process takes into account several important considerations including the recovery of the Company's total costs of providing service and that rates are fair, stable and equitable to all customers. The costs of providing standby service to a DG customer is not limited to only the energy (fuel) costs. Additionally, a customer's DG system most often serves only a partial portion of its total power requirement, and he continues to be connected to the system grid. The utility has the responsibility to plan to be able to serve that customer's total power requirement at any time, and on demand --- and there are costs associated with the utility's ability to serve customers load on demand.

HREA-HECO-T-5-IR-5

Would not the application of customer retention rates (pages 19 – 20) result in rate impacts? Please explain.

HECO Response:

Yes. Customer retention rates result in rate impacts. Customer retention rates are designed to retain loads for recovery of fixed cost-related revenues from customers with viable alternative energy suppliers. The energy rate discounts these customers receive result in lower (smaller) 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.

HREA-HECO-T-6-IR-1

On page 4 (lines 7 – 9), what does the phrase "so that non-participating customers are not burdened" mean?

HECO Response:

Please see the response to HREA-HECO-T-1-IR-8.

HREA-HECO-T-6-IR-2

On page 5 (lines 16 – 20), you are suggesting that non-participating ratepayers would be better off if the utility owned and operated CHP systems. You emphasize the potential rate impacts due to loss revenues from installation of non-utility DG. Would not there also be potential rate impacts due to utility investments that would be rate-based? Have you compared the potential rate impacts for both cases in detail, i.e., non-utility vs. utility owned DG?

HECO Response:

See the response to HREA-HECO-T-1-IR-6.

HREA-HECO-T-6-IR-3

On page 6 (lines 27–28), is it not also possible that non-utility CHP systems can help avoid reserve margin shortfalls?

HECO Response:

Yes, it is possible. Please refer to Mr. Sakuda's testimony in HECO T-3, page 9, lines 20 to 22, which states that "In HECO's analysis of the proposed Utility CHP Program, no differentiation was made between utility and non-utility CHP with respect to their firm capacity ratings and their ability to defer firm central-station capacity." Given this, non-utility CHP could also help avoid reserve margin shortfalls. See also HECO T-3, page 9, line 19 through page 10, line 12.

HREA-HECO-T-6-IR-4

On page 7 (lines 16 – 22), hasn't restructuring, in fact, already occurred in Hawaii despite our lack of island-to-island interconnection? For example, 24% of the HECO system's wholesale electricity is purchased from Independent Power Producers. Also, don't we already have retail competition, in the form of net energy metering and some dozen or so CHP systems?

HECO Response:

Electric industry "restructuring" as applied in some Mainland jurisdictions, has not occurred in Hawaii. There is competition with respect to the ownership of generation in Hawaii, largely due to PURPA. There is also competition at the retail level as a result of customer-sited generation. See response to COM-HECO-DT-IR-53. 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 in the Collaborative Report, October 19, 1998, Docket No. 96-0493, as well as the Commission decision and order referred to in HECO T-6, page 7 (lines 11-12).

HREA-HECO-T-6-IR-5

HREA understands HECO supports a competitive market with a level playing field in Hawaii for DG. Given that, please explain how HECO's estimate of an 88% utility share of the CHP market (7,700 kW out of 8,700 kW by 2009 per HECO's Exhibit HECO-104) comports with the concept of a competitive market for DG in Hawaii.

HECO Response:

A competitive market will exist even if the utility is ultimately able to own and operate a majority of the CHP installations. HECO's estimate of its potential market share is based on its understanding that customers will be receptive to the local utility ownership option, not because other service providers will be excluded from the market, or excluded from offering a third-party ownership option. A market is not made more "competitive" by excluding the preferred option from the market. Non-utility CHP developers in Hawaii have historically included equipment manufacturers (e.g., Pacific Machinery, Hess) and energy services companies (e.g., Johnston Controls, Honeywell, Noresco). The utility will be purchasing CHP equipment from the manufacturers and doing so in a competitive fashion, via the Companies' new CHP equipment procurement process that is described in HECO T-1, page 32.

The utility also is not offering balance of central plant equipment and services, which is the focus of most energy services companies and which in many cases goes hand-in-hand with a CHP project. The balance of central plant equipment and services in most cases dwarfs the CHP component of a customer's facility. For example, the CHP portion of a central plant may represent only 20% of the entire central plant value. Thus, the Companies' CHP projects will be complementary to the central plant services and equipment of the energy services companies.

In addition, the Companies' CHP forecast in HECO-104 anticipates that a fair amount – roughly 20% – of the CHP projects will be independently developed by customers, manufacturers, or energy services companies. In short, all parties will have fair opportunities to offer equipment and services to customers.