TESTIMONY OF

ROSS H. SAKUDA, P.E.

DIRECTOR
GENERATION PLANNING DIVISION
POWER SUPPLY PLANNING AND ENGINEERING DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Generation Avoided Costs,
Need for Utility Combined Heat and
Power ("CHP") Capacity,
Distributed Generation ("DG")/CHP
and Integrated Resource Planning,
Reserve Capacity, Spinning Reserve
and Operating Reserve, and
Reduction of Fossil Fuel Use

INTRODUCTION

Q. Please state your name and business address.

A. My name is Ross Sakuda and my business address is 820 Ward Avenue, Honolulu, Hawaii.

Q. What is your present position with Hawaiian Electric Company, Inc.?

A. I am the Director of the Generation Planning Division in the Power Supply Planning and Engineering Department. My educational background and experience are given in HECO-300.

Q. What will your testimony cover?

A. My testimony will cover:

1) generation avoided costs (Issue #6),
2) need for Utility Combined Heat and Power ("CHP") capacity,
3) evaluation of HECO's, HELCO's and MECO's (collectively the "HECO Utilities") proposed Utility CHP Program, (Docket No. 03-0366);
4) reserve capacity, spinning reserve and operating reserve, and
5) reduction of fossil fuel use (Issue #8).

GENERATION AVOIDED COST

Q. What is Issue No. 6 in the instant docket?

A. Issue No. 6 states "What utility costs can be avoided by distributed generation?"

Q. What is the HECO Utilities' position on this issue?

A. The HECO Utilities' position is that distributed generation ("DG") has the potential to defer or avoid the following utility costs:

1) new central station generating capacity and fixed operation and maintenance ("O&M") costs;

2) utility central station generation fuel and variable O&M costs to the extent they displace utility generated energy; 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.

My testimony will cover the first two items. Avoided T&D capacity will be covered by Ms. Shari Ishikawa in HECO T-4.

HECO Utilities' Capacity Planning Criteria

Q. What is the purpose of the HECO Utilities' capacity planning criteria?

A. The purpose of the HECO Utilities' capacity planning criteria is to provide a set of rules and guidelines to determine the amount of firm generating capacity needed on the system to maintain a certain level of generating system reliability.

Q. What are the HECO Utilities' capacity planning criteria?

A. The capacity planning criteria for HECO, HELCO, and MECO are shown in HECO-301, HECO-302, and HECO-303, respectively.

Q. What is "firm capacity?"

A. 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.

Q. Can DG be considered firm capacity?

A. Yes, in many instances, DG can be considered firm capacity. In order for a 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.

Q. If DG can be considered firm capacity, can it defer the need for new central station generating capacity?

A. Yes, if the DG can be considered firm capacity and the DG facility (or multiple DG facilities in aggregate) are sufficiently large, it can defer the need for new central station generating capacity.

Q. How do the HECO Utilities apply their capacity planning criteria to determine whether or not firm DG can avoid new central station generating capacity?

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

<u>Avoided Costs</u>

Q. What are avoided costs in the context of this proceeding?

A. Avoided costs are the incremental or additional costs to the utility of electric energy or firm capacity or both which costs the utility would avoid as a result of the installation of distributed generation. In general, avoided costs consist of several components:

1) avoided generation capital costs;
2) avoided generation fixed operation and maintenance ("O&M") costs;
3) avoided energy costs;
4) avoided variable O&M costs;
5) avoided transmission capital costs;
6) avoided transmission loss costs;
7) avoided distribution capital costs; and
8) avoided distribution loss costs.

My testimony will cover the first four items. Items 5 to 8 will be covered by the testimony of Ms. Ishikawa in HECO T-4.

Avoided Generation Capital and Fixed O&M Costs

Q. What are avoided generation capital costs?

A. 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. 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 capital costs.

Q. What are avoided fixed O&M costs?

A. 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 (in any). 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 fixed O&M costs.

Avoided Generation Fuel and Variable O&M Costs

Q. What are avoided generation fuel costs?

A. 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. Energy produced by DGs can displace the energy that would otherwise be produced by utility central station generating units and can result in avoided generation fuel costs.

Q. What are avoided generation variable O&M costs?

A. 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. These costs include such items as chemicals for water treatment, potable water costs where the water is used directly by the generating unit (such as in water injection for NO_X abatement in combustion turbines), lubricating oils, and overhaul costs for combustion turbines and diesel engines since the duration between overhauls is dependent upon the number of hours the units operate. 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 variable O&M costs are avoided.

Calculation of Avoided Costs

Q. How are avoided capital and fixed O&M costs calculated?

A. As explained earlier in my testimony, the HECO Utilities' capacity planning criteria are used to determine the appropriate years in which the firm capacity resources should be installed to maintain a given level of generating system reliability. To determine capital and fixed O&M costs that can be avoided by the installation of firm capacity DG, the timing of the installation of firm central station capacity must first be determined in a base case without the DG resources in the plan. Then the timing of installation of firm central station capacity must be determined in an alternate case with the DG resources in the plan. If the aggregate amount of firm DG capacity is sufficiently large, the installation year of one or more of the central station generating units will be deferred. The benefit of the deferring capital and fixed O&M expenditures for the central station generating units is then determined by calculating the difference in capital and fixed O&M costs between the base and alternate cases on a net present value basis. A detailed explanation is given in Exhibit HECO-304.

Q. How are avoided fuel and variable O&M costs calculated?

A. Avoided fuel and variable O&M costs are calculated using production simulations. Production simulations are performed using computer programs that simulate the operation of the generating units on the system based on the actual system operating parameters (such as forecasted demand, spinning reserve, economic dispatch, planned outage schedules, unit performance curves, fuel costs and other factors). The production simulation model calculates each unit's operating hours, energy production, and fuel and variable O&M costs. Production simulations are performed for a base case without the DG resources and an alternate case with the DG resources. Avoided fuel and variable O&M costs are the difference in fuel and variable O&M costs between the base and alternate cases.

NEED FOR UTILITY CHP CAPACITY

Q. Has HECO identified the need for new firm generating capacity?

A. Yes, it has. On Oahu, even with the continued implementation of the existing energy efficiency DSM program and the implementation of the proposed residential and commercial & industrial load management programs, it was determined in HECO's IRP-2 Evaluation Report (filed with the PUC on December 31, 2002 in Docket No. 95-0347) that new firm generating capacity would be needed in 2009. In HECO's Adequacy of Supply letter, filed on January 31, 2004, HECO indicated on pages 5 and 6 that because of a higher forecast for peak demand, "generating system reliability will fall below the 4.5 years per day reliability guideline beginning in 2006, assuming no new central-station generating capacity is added for 2004 through 2006, even if (1) forecasted peak reduction benefits (estimated at 11 MW for 2004-2006) from continuation of existing energy efficiency DSM programs are acquired, (2) proposed peak reduction benefits (estimated at 28 MW for 2004-2006) from the two load management programs are acquired, as forecasted in their respective applications [footnote excluded], and (3) proposed utility CHP impacts (estimated at 8 MW for 2004-2006) occur as forecasted in Docket No. 03-0366. Should the forecasted peak reduction benefits from these programs not occur, then the generating system reliability is expected to fall below the 4.5 years per day reliability guideline threshold sooner than 2006."

In other words, HECO has an urgent need for firm generating capacity. Even with the forecasted firm capacity contributions of the proposed CHP Program in combination with the energy efficiency and load management DSM program impacts, new firm capacity would be needed in 2006. Without the firm capacity from the CHP program, new firm capacity would be needed even sooner.

Q. Has MECO also identified the need for new firm generating capacity?

A. Yes, it has. MECO filed its IRP-2 Evaluation Report with the PUC on April 30, 2004, and identified firm capacity needs for Maui, Lanai and Molokai. On Maui, with the continuation of the existing energy efficiency DSM programs, the planned implementation of residential and commercial & industrial load management programs, and the proposed implementation of the Utility CHP Program, it was determined that new firm capacity would be needed in 2006 (Maalaea Unit 18) and 2010 (Waena Unit 1) in the near term. Without the capacity contributions of the Utility CHP Program, Maalaea Unit 18 would still be needed in 2006 but Waena Unit 1 would be needed in 2008. Therefore, utility CHP can have a significant impact on deferring central-station generation on Maui.

On Lanai, it was determined that new firm capacity will be needed in 2007. MECO currently plans to install CHP units to satisfy that need for capacity. Should those CHP units not be installed, the central-station generating unit (Unit LL-9) planned for installation in 2013 would need to be installed in 2007. Given the lead times for permitting, engineering, equipment procurement and construction, Unit LL-9 could be installed no earlier than about the 2009 timeframe.

On Molokai, it was determined that new firm capacity will be needed in

2012. No CHP installations are currently planned for Molokai.

Q. Has HELCO also identified the need for new firm generating capacity?

A. Yes, it has. HELCO filed its IRP-2 Evaluation Report with the PUC on March 31, 2004. It was indicated that with the continuation of the existing energy efficiency DSM programs and the proposed implementation of the Utility CHP Program, firm capacity would be installed in 2009 (Keahole ST-7) and 2017 (West Hawaii Unit 1). Keahole ST-7 will be installed as expeditiously as possible in accordance with a settlement agreement between HELCO and other parties. A land use reclassification process must be completed before the unit can be installed.

Q. Can CHP, whether utility or non-utility, help satisfy the needs for firm capacity identified?

A. Yes. As I have indicated, there is an urgent need for capacity on Oahu. CHP capacity can help satisfy that need. CHP, which is a form of DG, can be considered firm capacity where the utility is able to control the operations of and maintenance quality of the installation. The CHP should also have a reliable fuel supply and an adequate amount of fuel storage. The CHP must provide a compatible monitoring and control system to allow the utility to dispatch the CHP installation to allow for responsiveness to utility system conditions.

Q. What advantage does utility CHP provide over non-utility CHP?

A. 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. In reality, however, the extent to which a utility can rely on DG to reduce the load that has to be served by central station generation as a result of the installation of multiple DG units would depend on factors such as the relative sizes of the DG units, the reliability characteristics (e.g., forced outage rates) of the DG units, the duration of the DG installations, and the ability of the utility to coordinate scheduled maintenance or to require that scheduled maintenance take place during off-peak periods. Some, but not all, CHP system installations installed by third-parties, and operated and maintained by third-parties or customers themselves, can be expected to be as reliable as utility-owned CHP systems. The utility would have much more ability to schedule the maintenance of its own CHP systems. Utility systems are less likely to be disinstalled, on average, than some third-party systems. In addition, with utility participation in the CHP market via the Utility CHP Program, the CHP market will be expanded, as explained by Mr. Scott Seu in HECO T-1. Therefore, utility participation brings with it the advantage of additional central-station capacity deferral.

EVALUATION OF THE HECO UTILITIES' PROPOSED CHP PROGRAM

Evaluation of Utility CHP Program Cost-Effectiveness

Q. Did HECO evaluate the cost-effectiveness of the HECO Utilities' proposed CHP Program?

A. Yes, it did. In the HECO Utilities' application of October 10, 2003, to the PUC in Docket No. 03-0366 for approval of the proposed CHP Program, HECO described in detail the economic evaluation performed.

1) Page 16, Item 3, of the application described the quantitative analysis.
2) Section VIII on pages 51 to 61 described in detail the economic analysis performed, including the assumptions and methodology.
3) Exhibits A, B and G provided the numerical assumptions.
4) Exhibit H provided additional assumptions and the detailed calculations.

5) Workpapers H and I, which were submitted to the PUC on November 13, 2003, provided detailed calculations and results.

Q. Please briefly describe the analysis performed.

A. The analysis considered to two cases – the base case in which there is no utility CHP and only third party CHP and the alternate case in which there is both third party and utility CHP. In the alternate case (with utility participation), two things occur. First is that the majority of customers that would have otherwise installed third party CHP will install utility CHP. (Please refer to the testimony of Mr. Seu in HECO T-1 for the reasons for this occurrence.) When this happens, utility CHP simply displaces third party CHP and no new central-station capacity deferral benefit results. Second is that the CHP market as a whole is expanded. (Please refer to the testimony of Mr. Seu in HECO T-1 for the reasons for this occurrence.) The market expands because customers who would not have otherwise installed CHP will install CHP if it is a utility program. When this occurs, there is additional new central-station capacity deferral benefit over and above that without the Utility CHP Program.

If a utility does a CHP system project instead of a third-party, the utility incurs costs (in the form of the CHP system investment and O&M expenses for the system), but retains revenues that would otherwise have been lost. By doing cost-effective CHP system projects, the net effect is to benefit non-participating utility customers (i.e., customers that do not install CHP systems). By increasing the number of CHP systems installed, the utility can also avoid (i.e., defer) investment in central station generation (and avoid the variable expenses of producing and delivering the energy avoided by the CHP systems). As is shown in the CHP Application, the net effect is to benefit non-participating utility customers.

Q. How was it concluded that the Utility CHP Program was cost-effective?

A. It was concluded that the Utility CHP Program was cost-effective when the quantitative analysis, which took the factors identified in the CHP Program application into account, showed that the net present value of revenue requirements over a 20-year planning period were lower with the Utility CHP Program than without the Utility CHP Program.

DG/CHP in Integrated Resource Planning

Q. What is Issue No. 11 in the instant docket?

A. Issue No. 11 states "What revisions should be made to the integrated resource planning process?"

Q. What is the HECO Utilities' position on this issue?

A. No changes to the IRP Framework are required for the consideration of DG. In the current round of integrated resource planning for HECO (IRP-3), a significant effort is being made to consider DG and CHP technologies and their potential contribution to meeting the electrical needs of customers. By its nature, DG is difficult to analyze in this process. The IRP process analyzes resources at the system level prior to the identification of specific projects. That means that 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. An individual DG project is also generally too small to impact the timing of central station units or transmission line timing. In order to complete a fair evaluation, an aggregate forecast of DG resources must be considered as was done for CHP system in the analysis done for the CHP Program application in Docket No. 03-0366.

Q. Will the Utility CHP Program be evaluated in HECO's current integrated resource planning process (IRP-3) that is currently in progress?

A. Yes, it will.

Q. Please explain how the evaluation will be performed.

A. HECO plans to perform two separate evaluations of CHP in the HECO IRP-3 process currently in progress. The first evaluation will be performed as part of the main integration effort, where long-term resource plans are developed from combinations of demand-side and supply-side resources. The plans will consider two levels of CHP market sizes – one that is the best estimate of the CHP market level and the other a high or optimistic CHP market level. The market sizes will be considered the total of non-utility and utility CHP, i.e., the analysis will be independent of CHP ownership. The integration analysis will determine the impact of each market size on the selection and timing of demand-side and supply-side resources for each finalist resource plan. In order to simplify this analysis, it will exclude CHP costs (capital, O&M, or fuel) and CHP revenue impacts in the calculation of total resource costs for each of the finalist resource plans. Instead, this first analysis will focus on how different CHP market sizes have an effect on the timing and types of resources selected for the candidate resource plans.

The second evaluation HECO plans to perform is a supplemental analysis to demonstrate the impacts of CHP ownership (utility vs. non-utility) on total resource costs, utility revenues and utility revenue requirements. The focus of this second evaluation will be the impact to ratepayers of CHP resources as a function of CHP ownership. This evaluation will be limited to impacts to one resource plan – the utility's preferred resource plan. Impacts of CHP ownership will be made by performing calculations of total resource cost with and without utility participation in the CHP market, including the estimated cost for capital, O&M, and fuel for a Utility CHP Program. In addition, this supplemental analysis will also consider any changes in utility revenues due to discounts to electric rate tariffs, facilities charges, and thermal charges.

Q. When will the results of the evaluation be available?

A. It is estimated that the results of the evaluation will be available in about the first quarter of 2005, after the preferred resource plan has been selected.

<u>RESERVE CAPACITY, SPINNING RESERVE AND OPERATING RESERVE</u>

Q. What is "reserve capacity"?

A. Reserve capacity is the total amount of firm generating capacity on the system less the system peak demand. Enough reserve capacity must be maintained on the system to allow generating units to be taken out of service for maintenance and to allow for the unexpected loss of generating capacity due to unplanned outages of other generating units. Reserve capacity is commonly referred to as "reserve margin."

Q. Have any of the other parties to this docket taken a position on distributed generation and its ability to provide reserve capacity?

A. Yes. The County of Maui in their Preliminary Statement of Position stated on page 1 that "the backup generators of some of Hawaii's large energy consumers can be networked together to become 'virtual' backup power plants for the electric utilities." The virtual power plan concept was also identified by the County in MECO's second integrated resource planning process.

Q. What benefits does the County of Maui believe can be acquired from "virtual" backup power plants?

A. On page 4 of their Preliminary Statement of Position, the County of Maui states that "MECO would acquire access to a low cost and flexible 'virtual' backup power plant, consumer-generators would generate revenues, and onsite and grid reliability would improve."

Q. What issues need to be resolved in order for utilities to rely on "virtual" backup power plants to provide reserve capacity?

A. The HECO Utilities have identified a number of issues and concerns:

1) 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 power from the utility is not available. It is likely that when there is a system emergency and the utilities need backup power from such "virtual" power plants, the large customers would be affected by the same system emergency and would be calling upon their emergency generators to provide power. In such cases, the "virtual" power plants would not be able to provide backup power to the grid.

2) The air permit obtained by customers to operate their emergency generators may not permit operation in parallel to the grid, i.e., the units may be permitted to operate only for testing or to serve the customers' internal loads only in the event of an emergency.

3) The air permit may allow the unit to operate for only a very limited number of hours for testing and bona fide emergencies only.

4) Even if the air permits did permit the units to operate for a significant number of hours, neighbors of the customers with the emergency generators

may object to operation of the units for more than testing and emergencies. Their objections may be based on noise, emissions and increased truck traffic due to additional fuel deliveries.

5) HECO would have no control over the testing and maintenance practices for the emergency generators and thus would have no control over their availability or reliability.

6) HECO may not have adequate dispatch control over the units since the emergency generators would be designed for a customer's specific emergency needs and not necessarily for the needs of the grid.

7) Fuel storage capacity may be sufficient for emergency situations of short durations but may be inadequate for sustained grid backup needs.

Q. How do Independent Power Producers ("IPPs"), who provide power to the HECO Utilities under Power Purchase Agreements ("PPAs"), address these issues?

A. The PPAs contain provisions that provide assurances that the IPP will deliver capacity and energy to the utilities within certain performance and reliability standards when needed and specify penalties for non-delivery or sub-standard performance. The following are examples of typical performance standards, requirements and penalties:

1) Delivery voltage, frequency and reactive kilovar standards;
2) Scheduling and coordination of planned outages;
3) Planned maintenance outages durations and cycles;
4) Unit Equivalent Availability Factor;
5) Equivalent Forced Outage Rate;
6) Guaranteed capacity;
7) Power quality standards;

8) Maximum number of unit trips;

9) Adequate inventory of spare parts;

10) Utility has full dispatch rights; and

11) Liquidated damages (penalties) for:

   a) Reduced unit availability;

   b) Excess unit trips; and

   c) Firm capacity deficiency.

Q. What other distinctions must be considered between IPPs and "virtual" backup power plants?

A. The IPPs provide power only to the electric utilities. This is in contrast to the County of Maui's proposed "virtual" backup power plants, which would serve either a large customer's internal load under emergency conditions or the electric utility.

Q. Please summarize the HECO Utilities position on the "virtual" backup power plants.

A. The HECO Utilities would need to be assured that these "virtual" backup power plants would be available and capable of providing capacity when needed by the system. Until the above concerns can be resolved and it can be demonstrated that "virtual" backup power plants can reliably and cost-effectively provide reserve capacity, the HECO Utilities do not plan to integrate these types of resources into their long-range resource plans.

Q. What are "spinning reserve" and "operating reserve"?

A. The HECO Utilities distinguish between "spinning reserve" and "operating reserve." Spinning reserve refers to the total amount of reserve capacity that is on-line but not currently serving any load, i.e., the difference between the total normal top load rating of all operating units and the total output of all operating units. Spinning reserve is intended to immediately serve load in the event another operating unit trips out of service.

Operating reserve is similar to spinning reserve in that it is an amount of reserve capacity that is on-line but not currently serving any load. The purpose of operating reserve, however, is to keep supply and demand in balance when demand on the system is increasing or decreasing.

HELCO further distinguishes "regulating reserve" from spinning reserve and operating reserve. Regulating reserve is a subset of operating reserve. It is that amount of operating reserve that is controlled by the Automatic Generator Control system. The purpose of regulating reserve is to maintain the cushion for power fluctuation that can occur through changes in system demand or in fluctuations in power output from intermittent, as-available resources.

Q. Why are spinning reserve and operating reserve relevant in this proceeding?

A. In looking at the potential benefits of DG, there is a question as to whether DG can supply generation planning reserves (i.e., reserve capacity) and operating reserves. It is appropriate that this question be addressed in my testimony.

Q. What are the HECO Utilities' spinning and operating reserve policies?

A. HECO spinning reserves are based on the output of the largest running unit. HELCO and MECO only carry operating reserves.

Q. What is the HECO Utilities' position on whether DG can supply "generation planning reserves and operating reserves."

A. Reserve capacity is discussed earlier in my testimony. The extent to which DGs can provide reserve capacity and operating reserves will depend on a number of factors, including whether or not the DGs are firm and dispatchable by the utility, their operating mode, whether or not they are designed and capable of safely exporting power to the grid, operating permit limitations (if any), their power output ramp rates, the extent to which the units can ride through disturbances on the system, and the extent to which the utility can control the maintenance and reliability of the units.

Customer-sited emergency generation theoretically could contribute to a utility's reserve margin if such generation could be dispatched by the utility to meet its peaking loads, but there are practical difficulties that would have to be addressed. Substation-sited generation could contribute to a utility's reserve margin, and does so in the case of HELCO. Customer-sited DG may impact the load to be served by central station generation (and help to defer the need for central station generation), as is addressed in the HECO Utilities' CHP application, but would not contribute to the utility's reserve margin unless sized in excess of the customer-load, and the excess capacity was available for dispatch by the utility.

The characteristics of small DG units are such that they generally are not suited to provide spinning or operating reserves, since these types of reserves are provided by units that increase or decrease their outputs (i.e., ramp up or down) in response to changes in system frequency (e.g., due to changes in system load, or forced outages of generating units).

DGs in the form of wind turbines, photovoltaics ("PVs") or as-available hydro units would not provide reserve capacity or operating reserves. They cannot be counted upon to provide capacity and energy upon demand when needed by the system. Customer-sited DGs in the form of small internal combustion engines that are designed to operate at full load to serve a customer's minimum electrical demand would not be able to provide any planning or operating reserve. Fuel cells, which perform optimally in steady-state operation, may not be able to provide operating reserves because they cannot not ramp up quickly in output to meet system needs. In addition, the ramping up and down of a fuel cell could be detrimental to its life and performance.

REDUCTION OF FOSSIL FUEL USE

Q. What is Issue No. 8 in the instant docket?

A. Issue No. 8 states "What is the potential for distributed generation to reduce the use of fossil fuels?"

Q. Please summarize HECO's response to Issue No. 8, which addresses the potential for distributed generation to reduce the use of fossil fuels.

A. DG from renewable sources of energy directly avoids the burning of fossil fuels. Wind turbines and photovoltaic systems are the most likely form of renewable distributed generation. Additionally, certain types of distributed generation that use fossil fuel can be highly efficient, such as combined heat and power. The thermal efficiency of fuel usage in a combined heat and power system typically ranges from 85% to 90%, versus 35% to 40% for a conventional central station generating unit. Thus, roughly half as much fuel would be required by the combined heat and power system. Distributed generation of all types can also reduce transmission line losses, providing additional efficiency improvements and reduction in the use of fossil fuels.

The amount of fossil fuel reduction that might be achievable 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.

For example, the Companies' position is that CHP systems are technically and economically feasible. 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. For other types of distributed generation systems such as microturbines, fuel cells, wind turbines or photovoltaics, technical and economic feasibility in large part remain to be determined.

SUMMARY

Q. Please summarize your testimony.

A. My testimony covered the HECO Utilities capacity planning criteria and how they are used to determine whether or not DG can defer new central station generating capacity. I explained how avoided generation costs for capacity and energy are calculated. I explained the need for CHP capacity, which is especially urgent on Oahu, and described the methodology used to show the cost-effectiveness of the Utility CHP Program. I also provided an overview of how CHP will be analyzed in the integrated resource planning process. I also covered reserve capacity and explained that a "virtual" backup power plant as conceptually envisioned by the County of Maui would not be able to provide reserve capacity until the reliability of such a concept could be actually demonstrated. I also covered spinning reserve and operating reserve and the extent to which DG technologies could provide spinning reserve. Finally, I covered the potential for DG to reduce the use of fossil fuel and indicated that the HECO Utilities have not quantified the potential.

Q. Does this conclude your testimony?

A. Yes, it does.