HECO RT-5A
DOCKET NO. 03-0371

REBUTTAL TESTIMONY OF
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CONSULTANT
ON BEHALF OF HAWAIIAN ELECTRIC COMPANY, INC.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Doug Gegax and my business address is Box 3CQ, University Park, Las Cruces, New Mexico, 88003.

Q. What are your current positions?

A. I am a Principal in EnWater Resource Consultants, LLC, an energy and water consulting firm. I co-founded EnWater ten years ago. I also serve as Director of the Center for Public Utilities and Professor of Economics at New Mexico State University. I have been at New Mexico State University since 1984.

Q. Please summarize your professional expertise as it is relevant to this proceeding.

A. I have extensive experience in the areas of electric utility rate design and market structure analysis. Over the last fifteen years, I have provided written and oral testimony for federal and state regulatory agencies on topics such as unbundled rate design and electric industry restructuring. My clients have ranged from electric utilities, state and federal commissions as well as consumer advocates. Over the last twenty years, I have trained university students and industry employees about electricity industry structure and rate design. The Center for Public Utilities at New Mexico State University, of which I serve as director, produces issues conferences, training courses and instruction/training materials for commissioners and professional staff at firms and federal and state commissions in the telecommunications, electricity, natural gas and water industries. The training courses cover legal and restructuring issues in utility regulation, revenue requirements, cost allocation, bundled and unbundled rate design and resource planning and conservation. The National Association of Regulatory Utility Commissioners officially sanctions the programs offered by the Center for Public Utilities. A detailed description of my experience and educational background is given in HECO-RT-500A.

Q. What is the purpose of your rebuttal testimony?

A. My primary purpose is to respond to some of the issues raised in the direct written testimony submitted in this docket on behalf of the County of Maui and the Consumer Advocate.

Q. Please summarize your main points of rebuttal and your recommendations.

A. The issue of customer-owned generation is not a new concept and the solutions simply require some logical cost-based modifications of the existing tariff structure. First, rate unbundling is only necessary for the development of competition in the provision of electricity products and services in which some person other than the utility can legally sell to another person which is not the utility. Hawaii is not in that situation and, therefore, rate unbundling is not necessary. The United States has had customer-owned generation in competition with utility-owned generation for over 25 years since the passage of Public Utility Regulatory Policy Act in 1978; and the development of this competitive generation occurred without the unbundling of customer rates. With this in mind, the rate design solutions necessary to accommodate customer-owned distributed generation ("DG") can be characterized as cost-based modifications to the design of existing tariffs and do not require a complete overhaul of the tariff in the form of rate unbundling for all customers.

Second, the myriad of rate design issues raised by the County of Maui ("COM") in this investigation only serve to promote a very narrow interest and not the general interest of the State of Hawaii in that they would further special interests in the development of customer-owned DG through the discriminatory rate treatment of new or expanding customers and a subsidized rate design for DG customers. The proposals of COM would have the Commission completely throw out the time-tested methods of setting utility rates in favor of a regulatory system that is very discriminatory and administratively unmanageable going forward. Specifically:

1. their proposed method for establishing stand-by service rates is counter to established cost-causation principles and would likely create a subsidy for DG customers;
2. their proposed "hook-up" or "impact" fees for new customers on the system is discriminatory and inconsistent with sound economics and accounting;
3. their insistence on time-of-use rates complemented by significant metering investments as well as the proposed change to performance based regulation ("PBR") only serves to muddy the waters within which the Commission needs to address a few very specific rate design issues to further accommodate customer-owned DG.

The Commission's rate design rules that may come out of this investigation should focus on the development of cost-based, stand-by service rates and, possibly , wheeling service rates. These can be accomplished as simple additions/modifications to the existing tariff structure in the form of riders to certain customer classes within the tariff.

THE DESIGN OF RATES TO ACCOMODATE DISTRIBUTED GENERATION

Q. In his testimony, Mr. Herz on behalf of the Consumer Advocate ("CA") emphasizes the importance of unbundling the existing utility rates. Do you agree?

A. Rate unbundling is neither a necessary nor sufficient step to accommodate economic development of customer-owned DG. Mr. Herz presents a proposed rate solution, complete rate unbundling, to address the implementation of DG.

However, the CA has subsequently indicated that each utility should develop and have cost of service information, and apply appropriate tariffs that result in a DG customer being served at a cost that is not subsidized by non-DG customers, in place of total unbundling. In addition, rate unbundling alone is not a complete solution to designing rates for customers with DG, because the appropriate rate design for DG customers is different from that which is appropriate for customers who completely rely on the utility system to meet their full usage requirements. Therefore, it is common for utilities in unbundled rate jurisdictions to have additional tariffs sheets dedicated to serving the special case where a customer owns generation. Because Hawaii has not authorized competition that includes the wheeling of power over the utilities' transmission and/or distribution networks, there is only a need to have a section in the existing tariff that lays out the special rate design necessary to accommodate customer-owned DG arrangements. As far as I have seen, similarly situated jurisdictions have also addressed this special case in the same way and have not completely unbundled rates.

Given the administrative burden and expenses associated with approval and implementation of unbundled rates, I disagree with Mr. Herz's proposal because other, less drastic tariff rate design options offer a reasonable solution to meet the same objective. Furthermore, it does not seem prudent to unbundle the rates for all customers because the primary reason for unbundling the rates of retail customers is authorized retail competition, and this does not exist in Hawaii.

The appropriate rate design to accommodate the special nature of customer-owned generation is different than the rate design for full-requirements customers in that the rates, in part, must be based on reserved capacity requirements of the DG customer to insure for times when the DG facility is unavailable. Customers that own DG, but who remain connected to the utility's network, will require an adjustment to their existing tariffs in order to cover the costs related to standby service. Consequently, jurisdictions including those with unbundled rates have implemented this special rate design through a modification of the existing tariff.

Q. When is rate unbundling necessary?

A. Commission approval of unbundled rates is only necessary when an entity other than the incumbent utility is authorized to compete and sell electricity products or services to wholesale or retail customers connected to the electricity network and those products or services are delivered over the utility's transmission and/or distribution system. As far as I know, only those jurisdictions with competition have gone through the process to approve a complete set of unbundled rates. When competition is legally possible, unbundled rates serve as the cornerstone of nondiscriminatory access to the transmission and/or distribution system which remain monopolized. Unbundled rates provide customers and competitors the prices they will pay if they deliver power from a non-utility generator over the utility's network.

Because the electric utilities in Hawaii have an exclusive franchise over the sale of electricity delivered to customers over the transmission and distribution system, rate unbundling is not necessary. Furthermore, each island is a stand-alone system not interconnected with other utilities, and the islands are not interconnected. Therefore, there is no need to deliver or wheel power across the utility's system from one entity to another.

Q. What do you mean by "rate unbundling"?

A. As I stated in response to the previous question, rate unbundling becomes necessary in jurisdictions that have opted to allow competition in certain electric services delivered to wholesale or retail customers over the distribution and/or transmission system. Typically rate unbundling separates the rates into the following five service functions: generation, transmission, distribution, ancillary services and retail supply. Certain jurisdictions have allowed competition in the first and last two of these service functions with transmission and distribution services continued to be supplied by the franchised utility. Allowing such forms of competition causes the need to unbundle the rates.

The rate unbundling process is usually lengthy and administratively costly for the regulatory agency and the interested parties. Although a "revenue neutral" unbundling as suggested by Mr. Herz can be somewhat less administratively burdensome, there will continue to be a need to carefully develop the underlying functional costs to come up with the appropriate ratios used to separate the revenue requirements of each customer class into the various functions before the unbundled rates are computed. Although a revenue neutral unbundling may work the first time rates are unbundled, eventually the Commission will be faced with a new cost of service study designed for unbundled rates in future rate applications to adjust rates. At such time, the Commission will be faced with a difficult decision as to how to treat any subsidies that may be embedded in current rates. Complete removal of subsidies can cause significant rate increases on certain customer classes. One method would be to unbundle the subsidies as a stand alone rate element charged to each customer, thereby making them transparent to all, but the Commission should expect increased pressure to eliminate the subsidies once they become so visible. Such a subsidy rate element would be positive for those customer classes that provide the subsidy and negative for the customer classes receiving a subsidy. Once again, I cannot recommend rate unbundling in Hawaii because it is not necessary when other tariff modifications can be made to accommodate customer-owned DG and, therefore, rate unbundling as a rate design solution to accommodate DG does not justify the administrative burden and complications that can arise during the unbundling process.

I would like to reiterate one main observation that the reason jurisdictions which have opted for retail competition unbundle the rates is because traditional bundled rates designed to recover costs related to all five functions do not complement the introduction of competitive markets that rely on the transmission and/or distribution network because competitors and their customers should only pay non-discriminatory prices for the unbundled utility services they actually use (transmission and distribution). Because Hawaii has not opted to have retail competition, rate unbundling is not necessary because no person other than the utilities can sell power to customers via the transmission and/or distribution network. Wholesale wheeling for sales to wholesale customers is also not a possibility because none of the utilities in Hawaii are interconnected.

Q. But isn't DG a form of competition?

A. Customer investment in DG is a form of competitive bypass but the type of DG being discussed in Hawaii does not use the transmission and/or distribution system to deliver the energy produced by a particular DG customer for sale to other customers. In other words, the DG-produced electricity product is for self-consumption and cannot be sold to other wholesale or retail customers other than the utility (this possibility is discussed below).

Q. Does this imply that a DG customer is not using utility services?

A. No. Most, if not all DG customers, will remain connected with the utility's system and will continue to buy utility-generated power to meet a portion of their total requirements as well as backup and maintenance services for times when the customer-owned generation is not producing energy. Therefore, the only utility service that the DG customer is not using is that portion of energy produced by their own generation. Therefore, the task before the Commission should be to establish a rate design for DG customers which includes that portion of the costs associated with the utility's distribution, transmission, and generation capacity still relied upon by the customer who generates a portion of their energy needs. This can be done without complete unbundling of all customer rates.

Q. What if the DG customer sells energy and/or capacity to the electric utility?

A. If the DG customer sells energy and/or capacity to the electric utility, the distribution and/or transmission system will be used but once again there is no need to unbundle rates because the electricity products are not being sold directly to other customers. The generation is simply part of the mix of utility-controlled generation and delivery services are subsumed in the utility's bundled rates and need not be broken out. In jurisdictions wherein non-utility electric products are being sold to other customers, unbundling is necessary to ensure that the prices paid for the utility services are non-discriminatory.

Q. So if the Commission does not opt for unbundled rates what better alternatives are there?

A. The problem at hand is best solved by the appropriate cost-based rate design not by rate unbundling. A DG customer is unique in the way in which it uses the utility system and therefore must have uniquely designed rates. Such rate design must recover costs that otherwise would not be recovered under traditional rate design based on usage of the system. Specifically, a utility should use the principle of cost-causation to properly design the rates for the DG customer. DG customers require capacity (distribution, transmission, and generation) to back-up the customer if the DG is not generating energy and, therefore, fixed capacity or demand charges for such customers should be the primary method used to recover the costs related to such capacity provided by the utility.

Q. Does the appropriate rate design depend on who actually owns and operates the DG facility?

A. Yes it does. First, I will review the rate design issues in a situation where the utility owns and operates the DG facility on behalf of the DG customer. Second, I will turn my attention to the case where the DG facility is owned and operated by the customer. In either case, cost-based adjustments can be made to existing tariffs. However, the nature of the adjustments will be different depending on who owns the DG facility.

Q. What are the appropriate cost-based adjustments required to an existing tariff in a situation where the utility owns the DG facility?

A. If the DG facility is utility-owned and part of the utility rate base then, like central generation stations, the electricity provided by the DG facility is simply utility provided power. If the DG facility is located on the customer's premise then the customer's existing tariff can continue to be applied with two primary adjustments. First, an adjustment in the form of a discount to the bill would be appropriate in recognition that: (1) the customer is providing a site free of charge; (2) DG facilities such as combined heat and power ("CHP") systems use fuel more efficiently; and (3) DG facilities may result in the postponement of new transmission and central generation investments. Such a discount can be calculated through an energy credit applied to the total kWhs produced by the DG facility. Second, in the case with CHP systems, the capital costs of non-electricity generating components (e.g., cooling towers and absorption chiller units) used directly by the customer, and only the customer, would need to be recovered through an additional charge so that the full cost of such components are not paid for by non-participating customers.

Q. Does it matter if the utility-owned DG facility is on the customer-side of the meter as opposed to the utility side of the meter?

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

STANDBY SERVICE FOR CUSTOMER-OWNED DISTRIBUTED GENERATION

Q. What are the unique rate-design issues in a situation where the customer owns the DG facilities?

A. Customers that own DG, but who remain connected to the utility's network, will require an adjustment to their existing tariffs in order to cover the costs related to standby service.

Q. What is standby service?

A. Standby service is provided by a utility to allow a DG customer an opportunity to reserve the assurance that the utility will provide power – and delivery of said power – to that customer at times when the customer's own DG is unavailable. Because complete disconnection from the utility's network would require the customer to own and maintain its own backup power source and follow its own load precisely, most DG customers are likely to find network attachment to be the more attractive option. This is why standby service charges have become a focal point of discussion in DG investigations.

Q. What principles should guide the development of standby service charges?

A. Standby rates should reflect the cost to the utility of providing standby service. Standby service itself is a type of "insurance" that the utility will reserve the ability to deliver a certain generation amount over the utility's transmission and distribution system to the customer during times when the customer's DG is unavailable – regardless of when the DG may become unavailable. The utility's transmission and distribution system must be built and maintained to accommodate the customer's maximum load even if some of this load is satisfied by the customer's DG. This, of course, is due to the fact that there is always a possibility that the DG will become unavailable. Most of the utility's cost of providing standby assurance is associated with the fixed costs of the transmission and distribution system, a portion of the fixed costs of generation as well as additional customer-related costs associated with any additional metering and billing. The full cost related to transmission and distribution capacity should be included because this capacity is necessary to fulfill the standby assurance benefiting the DG customer. Additionally, the DG customer is not providing any delivery capacity.

Q. Why should the standby service rate only include a portion of the fixed costs associated with generation?

A. The utility's total investment in generation includes two general categories:

(1) capacity that is required to satisfy the expected demand of its customers; and,

(2) reserve capacity that is required for unexpected generation outages and other ancillary services necessary to ensure system reliability.

Full requirements customers are allocated their share of the costs related to both categories of generation capacity. The DG customer, on the other hand, has made an investment in generation capacity which, when available, satisfies a portion of their energy needs. Therefore, the DG customer has self-provided the first category of generation capacity listed above in order to cover a portion of their load. The DG customer, however, has not self-provided the capacity identified in the second category listed above. Therefore, the generation capacity cost attributable to the DG customer includes an allocation of the utility's costs associated with the second category of generation capacity.

Q. What about the portion of the DG customer's load that is not satisfied by available DG capacity?

A. This portion of the DG customer's load is subject to the rates in the existing tariff; that is, the rate elements that include the fully allocated cost of all utility functions provided by the utility.

Q. Are there any other costs associated with serving a DG customer that should be included in standby service?

A. Any costs associated with new facilities such as metering and distribution system upgrades that may be required to accommodate DG should also be recovered from the DG customer. These costs may need to be determined on a case by case basis. Furthermore, variation in the type of technology employed across DGs can affect ancillary service requirements and, hence, utility system costs. Once again, such costs would have to be identified on a case-by-case basis.

Q. Mr. Lazar promotes a rate design for DG customers, which includes a relatively low demand charge and relatively high energy charge. What is your response to this?

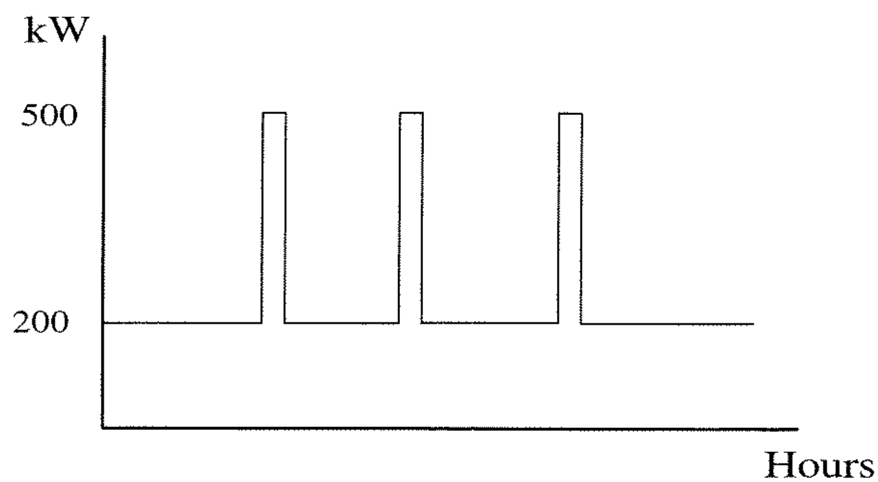
A. His proposal is highly inconsistent with cost-causation principles. Customer-owned and controlled generation provides a portion of the customer's energy needs but as long as the customer is connected to the utility's system, the customer relies on capacity that must be built into that system in the event the customer's generator is not producing electricity. The costs of such capacity reservation are fixed. They neither vary with the level of kilowatt-hours (kWh) of energy consumption nor with whether or not the DG is available or not. Standby service is a reservation of capacity analogous to insurance against an auto accident. I pay my insurance premiums even if I never get into accidents.

Mr. Lazar's proposal is based on the presumption that the DG customer uses the utility's system only during those times when the customer-owned generation is down for maintenance or is not in operation. This is not correct. In fact, the DG customer uses or relies on utility capacity even when the customer-owned generator is functioning normally and producing electricity. Because the utility must put forth and reserve sufficient distribution, transmission, and generation capacity in the event that the DG stops producing electricity, the utility has real tangible costs related to this investment relied upon by the DG customer. Only if the DG customer disconnected completely, would it no longer be relying on this utility system capacity and related costs.

Q. In general, how is a standby rate implemented?

Figure 1 (below) provides a simplified representation of the DG customer's demand on the utility's system. Figure 1 illustrates a situation where the customer self-generates a portion of their energy needs but meets the rest of their energy needs with utility-generated electricity. Figure 1 is for illustrative purposes only. The utility system is always there to make up the moment-to-moment difference between the customer's electricity usage and the amount of electricity produced by their generation, and from time-to-time the DG customer will meet their full energy needs with utility-generated electricity. The distribution, transmission, and generation capacity built into the utility's system must be sufficient to meet this moment-to-moment variation in their demand as well as the customer's full demand when the customer's generation is not producing electricity. This utility system capacity has a cost associated with it and this cost should be recovered from that customer throughout the year, not just during the times when the customer actually uses the capacity to deliver additional energy. Therefore, the appropriate design of rates for a DG customer based on cost-causation principles would include a demand charge large enough to recover the full cost associated with the capacity necessary to meet the customer's full demand at any time.

Figure 1



In Figure 1, the customer's total peak load is 500 kW and has a 300 kW rated DG unit. The remaining 200 kW load is served by full utility service, which includes demand charges found in the customer's existing tariff. The stand-by charge is applied to the level of the reserved capacity. This reservation amount should be equal to the DG rated capacity – 300 kW in Figure 1. As discussed above, the standby charge itself is lower than the demand charge applied to the portion of the load that is being normally satisfied by utility generation (200 kW in Figure 1) because standby charges include only a portion of the generation capacity. The 300 kW amount is the portion of the customer's peak load that is insured with the utility's stand-by service. Again, the standby charge applied to the 300 kW amount is lower than the demand charge in the customer's normal tariff. Thus, the DG customer pays the utility less in total than what it would have paid if the entire 500 kW is applied to the demand charges in the existing tariff. Of course when the DG facility is unavailable, the utility actually satisfies the full DG load (500 kW in Figure 1). In situations where the DG unit is unavailable, the backup generation capacity is actually being used and the customer is also required to pay the full costs attributable to the energy actually being produced by the backup generation.

Q. Do you think customer-owned DG should be promoted?

A. Yes, insofar as it is not subsidized as Mr. Lazar's standby rate proposal would do.

COUNTY WHEELING RATES

Q. Have you read the COM's testimony proposing the implementation of wheeling rates to allow them to deliver power from one location to another location?

A. Yes. This type of wheeling is also referred to as "self wheeling" in that the utility-provided transmission and distribution services connect a point of generation to a point of consumption where the generator-owning entity is the same as the consumption entity – in this case the County of Maui.

Q. What are the main points of the COM's testimony on county wheeling rates?

A. First, the COM feels that such self wheeling should be limited to public-sector customers primarily because such customers are permanent components of the community with access to cheap financing and because such customers own the streets and rights of way along which such delivery lines would run. The COM does not support general wholesale or retail wheeling: The COM only supports wheeling for counties. Second, the COM feels that county-only wheeling services would allow for cost-effective joint venture arrangements with renewable energy power producers.

Q. Are the COM's reasons why self-wheeling should only be granted to Counties reasonable?

A. No they are not. First, pineapple producers and some department store chains, for example, could also argue that they are "permanent components of the community" who might also benefit from self wheeling. Second, while non-government entities do not own streets and rights of way, they most certainly might be willing to pay wheeling fees that include such franchise costs. Third, the fact that non-government entities do not have access to tax-free bonding does not imply that the financing that is available to such entities is so cost prohibitive that they could not benefit from self wheeling. As a policy initiative, I believe that it will be difficult for the Commission to allow Counties access to self wheeling while prohibiting *all others* from such a service. Hawaii has spoken clearly that retail wheeling is not in the best interests of the State and it should carefully examine whether or not widespread self wheeling is in the best interest of the State as well.

Q. Regardless of who might be allowed access to self wheeling, what are the issues involved in developing a cost-based self-wheeling charge?

A. Cost-based wheeling charges include fully allocated transmission and distribution costs as well as fully allocated ancillary service costs. Mr. Lazar failed to include ancillary service costs in his description of wheeling fees. Typically, the wheeling charge itself is in dollars per kilowatt and is applied to the level of system capacity required by the self-wheeling customer.

Q. Is the issue of self wheeling relevant to this docket?

A. No. It is my understanding that self wheeling is not available under current Hawaiian law and would not be relevant to most DG customers.

END-USE CUSTOMER CONNECTION OR IMPACT FEES

Q. Have you read the COM's testimony promoting the introduction of "hook-up", "connection", or "impact" fees?

A. Yes, and their proposal is very troubling. They have suggested the implementation of an upfront charge on new or expanding customers to cover the installed facilities and equipment cost of generation and transmission capacity. They use rising capacity costs as the justification for such a policy and reference the Commission's approved line extension policy as an example of how this is already done. This proposal is highly inconsistent with sound utility economics in that it would create a new sub-class of customers within each existing class based on vintage of the customer. I note that the Commission already rejected a similar proposal put forth by Mr. Lazar when he served as a witness for the Consumer Advocate in Docket No. 6999, HELCO's 1992 test year rate case (See Decision and Order No. 11893, pp. 100-102, filed October 2, 1992), and I am not aware of any investor-owned electric utilities that have implemented a rate design similar to that proposed by Mr. Lazar.

Q. Can you elaborate on the troubling features of the "impact" fee proposal by COM's witnesses?

A. First, Mr. Lazar's description of the connection or impact fee is very shortsighted in that he discusses the calculation and implementation of such a fee as if the state of the world stood still, and, therefore, he fails to address the dynamic problems facing the Commission, the customers, and the utility moving forward in time. When one stops to consider the possibility of moving forward under such a policy, some very difficult questions and problems arise. Imposing such a connection cost on new or expanding customers the first time creates new sub-classes of customers based on vintage. The Commission and the utility will have to implement detailed accounting for the amounts collected from new customers and distinguish between capacity additions caused by growth versus capacity additions that are necessary to replace existing capacity. Even if the Commission establishes such accounting rules, the costs per unit of generation and/or transmission capacity can be expected to change through time. They can increase or decrease depending on the current cost of equipment and possible technological innovation. How frequently should the Commission require a new computation of the impact fee to ensure that it is reasonable? Keeping in mind that each time the impact fee is recalibrated, new customer sub-classes will again be created based on vintage. Following the first recalibration of the impact fee, you then will have three sets of customer classes based on vintage.

Mr. Lazar also fails to acknowledge that when existing capacity needs to be replaced, this will change the average cost of that existing capacity. Determining the fair and proper regulatory treatment of such average cost changes in the future when we have multiple customer classes based on vintage will be very difficult. One can begin to see the complications and debates that will arise in future rate cases when the Commission attempts to discern who is responsible for what capacity additions. For example, a new generation unit may in part add new capacity on the system and in part replace existing capacity. The Commission will now be forced in future rate cases to consider methods for splitting the costs associated with the new generation plant between the vintages of customers. Operation and maintenance costs on new generation capacity also vary greatly between types of generation. Suppose a new generation capacity uses technology with relatively high capacity costs but relatively low operating (fuel) costs. Mr. Lazar seems to suggest that new customers should be responsible for the capacity costs but all customers would benefit from the reduced operating costs. For these reasons, the implementation and management of such a policy will be extremely burdensome on the regulatory process if not unmanageable.

Second, Mr. Lazar discusses generation capacity as if all capacity is of the same type and designed for the same purpose. In reality, the optimal mix of generation capacity types and the decision to add capacity to that mix depend on current system load characteristics. To begin distinguishing "new" capacity from "old" capacity is contrary to the economics associated with an optimal mix of generation. The mix of generation in the system must be viewed as one integrated resource serving all customers. This is an important task in the Commission's Integrated Resource Planning process. It may be optimal at a particular point in time to add a base load plant with higher per-kW capacity costs than peaking capacity. The impact fee proposed by the COM would hold new customers responsible for that new capacity despite the fact that its addition is optimal for the system as a whole. In other words, the entire set of generation capacity using a range of technologies is shared resource in the service of all customers regardless of the vintage of the customers.

Third, the Commission should expect several disputes to arise when the utility attempts to implement impact fees for common facility costs. Determination of new customer capacity needs alone is likely to draw formal complaints before the Commission.

Finally, the proposal would increase the investment cost of developing real property by residents and businesses. Prospective new home owners will now face inclusion of an additional amount in their mortgage principal; thereby stifling home ownership.

Q. But the line extension policy includes a form of connection charge already, correct?

A. There is a fundamental difference between the facilities covered by the line extension policy and the facilities associated with generation and transmission. Line extensions involve distribution facilities that are dedicated to serve a particular customer or a distinguishable set of customers say in a new housing development or industrial park. Therefore, the line extension policy seeks to recover the costs of such dedicated facilities from the set of customers clearly using those distribution lines. Implementation of the line extension policy itself is complex despite the fact that it is limited to such dedicated facilities. Generation and transmission facilities, on the other hand, are used in common by all customers on the network. A suggestion that the Commission should begin dissecting facilities that clearly benefit the network as a whole based on individual customer vintage is inconsistent with proper allocation of shared network costs and discriminatory.

TIME OF USE RATES

Q. Have you read the COM's testimony proposing the implementation of mandatory time-of-use rates?

A. Yes.

Q. What is you reaction to that testimony?

A. Currently, HECO, HELCO, and MECO have time-of-use rates in place for some of their customers as discussed by Ms. Seese in HECO RT-5. Time-of-use ("TOU") rates are a form of demand-side management wherein the objective is to redistribute load away from system-peak times. Such rate design also recognizes the fact that satisfying load during system peak times is more costly as peaker units (with higher operating costs) are put on line. TOU rates fall under the more general category of "distributed energy resources" ("DER"). DG facilities also fall under the DER umbrella. As per Commission Order No. 20582, the focus of this docket is specifically on distributed generation. And while "[o]ther DER technologies may be addressed in this docket to the extent they raise the same interconnection and policy issues that the distributed generation technologies raise", I believe that the issues surrounding TOU rates are significantly different than those surrounding DG development. Therefore, I will not respond further on the COM's testimony regarding TOU rates.

PERFORMANCE BASED REGULATION

Q. Have you read the COM's testimony proposing the implementation of performance-based regulation ("PBR")?

A. Yes.

Q. What is you reaction to that testimony?

A. I believe a properly structured PBR has merit. However, as with my response to TOU rates, I believe that the issues surrounding the implementation of PBR are outside the objectives of this docket. Therefore, I choose to not respond further on the COM's testimony regarding PBR.

CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions and recommendations.

A. 1) Unbundling is neither necessary nor sufficient for the determination of fair cost-based rates for DG customers. Unbundling is only necessary to accommodate situations where non-utility generators sell to non-utility customers. Design of rates to accommodate customers who own DG involves a modification of the existing tariff and unbundled rates for all customers does not further that objective.

2) The rate design proposals put forth by the COM are very extreme in nature and inconsistent with sound, cost-causation principles.

My primary recommendation based on these two primary conclusions is a modification to the existing tariff to establish cost-based stand-by service consistent with the principles put forth in this testimony. Eventually, in a future rate case, DG customers may be in their own rate class under their own tariff schedules.