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October 22, 2004

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PUBLIC UTILITIES COMMISSION

Public Utilities Commission
State of Hawaii
465 South King St., Rm. 103
Honolulu, HI 96813

ATTENTION: Chief Clerk of the Commission

Re: In the matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate Distributed Generation In Hawaii; Docket No. 03-0371

Dear Chief Clerk of the Commission:

Enclosed for filing is COUNTY OF MAUI'S SIMULTANEOUS WRITTEN REBUTTAL TESTIMONIES OF EXHIBIT COM-RT-1, KAL KOBAYASHI, ENERGY COORDINATOR, AND EXHIBIT COM-RT-2, JIM LAZAR, CONSULTING ECONOMIST; CERTIFICATE OF SERVICE (Original + 12).

Please return the two (2) additional file-marked copies to this office. A self-addressed, stamped, envelope is enclosed for your convenience.

If you have any questions, please do not hesitate to contact me.

Sincerely,

Cindy Y. Young
CINDY Y. YOUNG
Deputy Corporation Counsel

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Enclosures
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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of	)	
	)	
PUBLIC UTILITIES COMMISSION	)	
	)	DOCKET NO. 03-0371
Instituting a Proceeding to Investigate Distributed Generation in Hawaii.	)	

COUNTY OF MAUI'S SIMULTANEOUS WRITTEN REBUTTAL TESTIMONIES OF EXHIBIT COM-RT-1, KAL KOBAYASHI, ENERGY COORDINATOR, AND EXHIBIT COM-RT-2, JIM LAZAR, CONSULTING ECONOMIST

CERTIFICATE OF SERVICE

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PUBLIC UTILITIES COMMISSION

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate Distributed Generation in Hawaii.	DOCKET NO. 03-0371

COUNTY OF MAUI'S SIMULTANEOUS WRITTEN REBUTTAL TESTIMONIES OF EXHIBIT COM-RT-1, KAL KOBAYASHI, ENERGY COORDINATOR, AND EXHIBIT COM-RT-2, JIM LAZAR, CONSULTING ECONOMIST

COM-RT-1

Before the Hawaii Public Utilities Commission

Rebuttal Testimony of
Kalvin Kobayashi, Energy Coordinator

On Behalf of
County of Maui

Docket No. 03-0371

October 22, 2004

Exhibit COM-RT-1
Rebuttal Testimony of Kal Kobayashi
On Behalf Of
County of Maui

Q. Are you Kal Kobayashi, the sponsor of the County of Maui's direct testimony, COM-T-1?

A. Yes, and I will provide rebuttal testimony on issues including:

- Whether HECO should own customer-sited DG systems and primarily sell the DG-produced electricity and related non-utility services (i.e., hot water, air conditioning, maintenance, fuel supply, emergency power, energy management and information, power quality, and other energy services) to the customer hosting the DG installation. I will explain why the conclusions and decisions of this Commission and of other public utility commissions provide sufficient reasoning and precedent to disallow investor-owned utilities from owning privately used DG systems. I will also explain why HECO should not own consumer CHP systems, from a disruptive technology perspective.

- I will discuss alleged and potential market power issues and how it could affect consumer choice and the need for a new power plant on Maui.

- The role of the Commission, as recommended by HECO.

Q. Are you sponsoring rebuttal exhibits with this testimony?

A. Yes. I am sponsoring the following exhibits:

1. Exhibit COM-R-101: This is a May 1999 PMA Online Magazine article summarizing the Louisiana Public Service Commission's decision relating to whether the provision of non-public services are subject to the jurisdiction of the Public Service Commission.

2. Exhibit COM-R-102: This is an Opinion of the New Mexico Supreme Court that explains why the court affirmed the New Mexico Public Service Commission's determination that treating utility-related non-utility service programs as tariffed utility services creates several possible problems, including a concern about real or potential cross-subsidies, potential liabilities, and claims of antitrust or unfair trade practices.

3. Exhibit COM-R-103: This is an excerpt from the National Renewable Energy Laboratory publication, "Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects," which documents an allegation of market power activities by HECO in Hawaii.

Q. What issue will your rebuttal testimony first address?

A. I will start by addressing the issue of whether the utility should be allowed to own privately used DG systems. I begin by distinguishing what constitutes public and private uses of DG systems, in the context of public utility statutes.

Q. Did HECO make any statements relating to what constitutes the public or private use of DG systems, in the context of public utility statutes?

A. In the Bonnet testimony, T-6, at pages 10-11, HECO identifies a situation that could be viewed as a public use that could fall within the purview of public utility statutes:

> Finally, in the case of customer-sited CHP systems and DG owned by third-parties, the Commission's role is to review whether the retail sale of electricity by such third-party owners falls within the purview of the public utility statutes. To date, the Companies have not take the position that these third-party owned installations should be regulated by the Commission, due to the relatively small number of such installations.

Q. Do you agree that the Companies have not taken a position on this matter?

A. No. This statement fails to recognize that in 1984, HECO did take a position on whether the sale of electricity by a third-party DG owner to an individual customer constitutes a public use that falls under the purview of public utility statutes. In an appeal of the Commission's conclusions in Docket No. 4779, HECO argued that pursuant to HRS §269-1, the sale of electricity by a third-party DG owner to an individual customer was a public utility service because the DG system was dedicated for indirect public use (i.e., the customer would sell any excess energy to the public utility). However, the Commission found that the DG system was <u>not</u> dedicated for public use. Therefore, since the DG-provided electricity was a <u>not</u> a public utility service pursuant to HRS §269-1, the Commission concluded that the DG service provider was <u>not</u> a public utility. The Hawaii Supreme Court affirmed the Commission's determination with the following statement (for the complete Supreme Court Opinion, see the County of Maui's response to HECO's Information Request, Number HECO/Maui-DT-IR-41, pages 53-55):

> The PUC found that WPPI-III's[1] property was not dedicated to public use even though WPPI-III sold all of the electric energy produced by WPPI-III to WWC[2], which in turn sells the excess energy to Helco. Upon review of the record, we cannot conclude that the PUC's finding was clearly erroneous.

Q. Why is this past finding of *public* use important?

A. The finding that WPPI-III's DG system was not dedicated to *public* use is important because for WPPI-III, it meant that their *private* DG system would not be regulated by the Commission. The finding is important for other owners of *private* DG systems, such as

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[1] WPPI-III represents for Wind Power Pacific Investors-III.

[2] WWC represents Waikoloa Water Co., Inc.

HECO as they propose in their suspended CHP program and CHP tariff, because the finding should also apply to them.

Q. Did HECO's testimony recommend Commission action on their suspended CHP application?

A. Yes. In the Bonnet testimony, T-6, at page 11, HECO recommends:

> In order to facilitate the successful deployment of DG, the Commission should approve the Companies' proposed CHP program and CHP tariff, and expeditiously review and approve applications for individual CHP projects under Rule 4 of the Companies' tariffs.

Q. How is the Commission's past finding relevant to HECO's recommended approval of their proposed CHP program and tariff request?

A. HECO's recommendation implies that the Commission should either regulate the proposed CHP services as public utility services, pursuant to HRS §269-1, or allow public utilities to provide non-utility services on a regulated basis. Regarding the former, the proposed CHP program provides CHP services to individual customers, similar in nature to the aforementioned WPPI-III service offering. Therefore, HECO's proposed CHP systems are *private* systems that should <u>not</u> be regulated by the Commission. Regarding the latter, public utilities have the obligation to provide public utility services, however, public utilities do not have the obligation to provide privately used, non-utility services, nor have they been allowed to do so.

Q. Did HECO provide any past precedents where public utility commissions have allowed investor-owned public utilities to provide private or non-utility services on a tariff basis?

A. No, and HECO has also stated publicly that no investor-owned utility in the country provides CHP services.[3] There is good reason for allowing utilities to only provide public utility services. Public utility services are considered to be natural monopolies and it is in the public interest to allow and regulate these natural monopolies. Privately used DG and CHP services are not natural monopolies and the public interest is best served when competitive DG and CHP enterprises compete in a fair marketplace. Market power issues could arise if a regulated electric utility were to be allowed to compete against unregulated companies. I discuss market power issues later in this testimony.

Q. Are you aware of any non-utility services that have been regulated on a tariff basis in Hawaii?

A. No, but the Commission has allowed utility affiliates to provide un-tariffed, non-utility services. For example, photovoltaic systems were sold by ProVision Technologies,

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[3] Statement made during a MECO presentation to the Maui County Council Committee on Energy and Economic Development on June 19, 2003.

wind systems were developed by Hawaii Renewable Energy Systems, and energy management services, conceivably including DG systems, were offered by HEI Power Corp., all affiliate companies of HECO.

Q. Are you aware of any non-utility services that have been regulated on a tariff basis on the mainland?

A. No, and I have come across two public utility commission proceedings that exemplify why non-utility services have not been regulated on a tariff basis. Summaries follow:

1. The Louisiana Public Service Commission ("PSC") determined that a cogeneration facility co-owned by Entergy Power, an unregulated subsidiary of Entergy Corporation, should not be regulated because the facility was not offered for public use. This finding of *public* use is similar to the Commission's finding of *public* use in the aforementioned WPPI-III proceeding. A May 1999 PMA Online Magazine article, Exhibit COM-R 101, summarizes this aspect of the Commission's decision:

> Because the facility would not be providing retail electric service to the public, and because the facility would have no captive customers and not subject ratepayers or utilities to risk, the PSC found the owners do not provide electric service to the public and are therefore not subject to the jurisdiction of the PSC.

2. The New Mexico Public Utility Commission ("NMPUC") denied a request by PNM Electric Services ("PNMES"), an unincorporated division of Public Service Company of

New Mexico ("PNM"), to provide certain non-utility services on a tariff basis, in Case No. 2668. The proposed non-utility services were transient voltage surge suppressor, maintenance and repair, energy information services, and power quality solutions. The New Mexico Supreme Court affirmed the NMPUC decision (see Exhibit COM-R102).

Q. How is this PNMES request similar to HECO's proposed CHP program request?

A. The PNMES justifications for their request is similar to HECO's justification for its CHP program request. The following is from page 4 of Exhibit COM-R102:

> *(6)* PNM Gas and Electric Services delineated the following goals for the optional service programs: to continue to be responsive to customer needs by offering services that are complementary to the existing utility businesses; to improve competitiveness; to improve safety and provide choice in the marketplace; and to build upon the core business of providing utility services by offering new energy-related options to eligible customers who would enter into contracts with PNM for the optional services.

HECO's justifications for its CHP program request are detailed in their suspended CHP program request and are summarized in Seu testimony, HECO T-1, at pages 15-16. The aspects of HECO's justification that are similar to the above PNM justification include the following:

> 1) The provision of CHP services by utilities is a natural step in the evolution of electric utility services, and electric utility customers should have the option of acquiring CHP systems from Hawaii utilities...
>
> 6) Utility participation in the CHP market provides the utility customers with one more option to meet their energy

> needs -- in the words of one customer; it means "one stop shopping". Customers want to focus on what they do best and let the utility do what it does best: (a) own, operate and maintain power facilities; (b) manage fuel procurement for power facilities; and (c) manage electrical system interface.

Q. Does the County of Maui ("COM") agree with HECO's justifications?

A. No. The COM's expert witness, Mr. Lazar, believes that HECO may not be the best company to own, operate, and maintain DG systems and stated the following in his direct testimony, COM-T-2, at page 23:

> Finally, utilities have expertise in central generating station equipment. The distributed energy resource market uses different technologies, and requires different expertise. Alternative suppliers may be best able to provide this. Since much of the equipment used in the distributed energy resource market is more similar to that used in shipping and trucking, there are other suppliers in Hawaii that may be better equipped to provide and service such equipment than the utility.

I also believe that HECO may not be the best company to own, operate, and maintain DG systems. I point to the fact that HECO has not demonstrated competencies beyond their core capabilities, relative to the failures of HECO's affiliate companies, Hawaii Renewable Energy Systems, HEI Power Corp., and ProVision Technologies.

Q. Are the COM's concerns about HECO's capabilities important?

A. HECO's capabilities to own, operate, and maintain DG systems are important because if HECO provides those services in an incompetent or inefficient manner, then ratepayers could end up absorbing the business expenses resulting from the mismanagement of HECO's proposed CHP program. This creates a situation where captive ratepayers may bear the risk of new energy systems, while the potential benefits accrue only to certain customers.

Q. What were the reasons for NMPUC's denial of PNMES request?

A. The NMPUC's reasons for denial were summarized by the New Mexico Supreme Court, page 4 of Exhibit COM-R102:

> *(7)* However, the Commission responded with similar reason in Cases 2655 and 2668 for rejecting the optional service plans. Primarily, the Commission stated that the optional services consisted of "utility-related non-utility services." As such, the Commission held that it would be inappropriate to treat these non-utility services as tariffed utility services under the New Mexico Public Utility Act, NMSA 1978, §§ 62-3-1 to 62-3-5 (1967, as amended through 1996). Therefore, the Commission disapproved of PNM's applications and proposed rates. The Commission reasoned that treating optional service programs as tariffed utility services created several possible problems, including a concern about real or potential cross-subsidies, potential liabilities, and claims of antitrust or unfair trade practices.

Q. Does the County of Maui share any of the same concerns as the NMPUC?

A. Yes. Direct testimony by Mr. Lazar discussed our concerns about the use of cross subsidies as an exercise of market power, at COM-T-2, pages 19-21. Mr. Lazar further discusses market power issues associated with HECO's involvement in CHP in his rebuttal testimony, COM-RT-2, at pages 2-6. I discussed the issue of market power and claims of unfair trade practices in my direct testimony, COM-T-1 at pages 9-11.

Q. In your direct testimony on page 10, you referred to an allegation of market power. Can you provide some details of this allegation?

A. The following accounting is from the National Renewable Energy Laboratory ("NREL") report, "Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects."

1. Technical barriers. The follow is from pages 61 and 62 of the NREL report:

> - The utility requested a lightening arrestor that costs \$20,000. The developer is still negotiating with the utility and the issue has not yet been resolved. The lightening arrestor is for the underground 12.4-KV primary voltage line. No other location in the state has this equipment installed at this time.
>
> - The utility requested that a breaker rated for 2000 amps be installed on the low voltage side of the transformer. The building already has 2 separaate 1600-amp breakers (for two separate feeders). The equipment specified has not been made since 1982, and GE quoted a cost of \$40,000 and six months lead time. This was pointed out to the utility, and the requirement was dropped.
>
> - The utility stated that the high voltage feed was not grounded, and an inspection was required to prove that a high-voltage ground existed. Scheduling the inspection took one month.

> The utility requested a reverse power relay, even though this installation is an induction generator that requires an outside source of voltage to operate. The original relay specified by the utility was not appropriate for the installation, and General Electric (supplier of the relay) would not warranty it in the application. The utility agreed to a different relay as specified by General Electric; however, this process took an additional eight weeks. The utility required synchronizing equipment an parallel operation monitoring for the induction generator that has a reverse power relay installed that shuts down the entire cogeneration plant. This cost was over $6,000 for equipment that the developer argued was unneeded.

2. Regulatory barriers--back-up charges. The follow is from page 62 of the NREL report:

> When the project was proposed, the utility had no standby charges in their tariff. During the project development, the utility requested a $1,200/kW-year standby charge from the PUC. However, the request to the PUC was rejected on the basis that 120 kW could not affect the grid.

3. Business practice barriers--anti-cogeneration campaign. The follow is from page 62 of the NREL report:

> The utility has openly discouraged its customers from installing cogeneration facilities and switching to cheaper more-efficient power. In a publication sent to all customers, the utility stated that cogeneration is inefficient and expensive.

4. Business practice barriers--discount tariff. The follow is from page 62 of the NREL report:

> The utility also stated that the economics of cogeneration were difficult because of the lack of availability of natural gas. Yet, the utility was offering discounts to customers that did not install their own generation source. The utility had introduced a tariff reduction of 11.77 percent for customers who seriously considered cogeneration but opted to stay with

> the utility. The tariff required the customer to conduct economic analyses showing the savings associated with cogeneration. In addition, the customer must provide cost estimates from vendors showing the cost savings.

Q. Are there other similar concerns to that of the NMPUC that are relevant?

A. Yes. Let me start with the market power issues brought up in the instant proceeding. Market power issues were identified by two former intervenors, Pacific Machinery and Johnson Controls, in their complaint letter to the Commission, dated July 1, 2003. Said market power issues were incorporated by the Commission in the instant proceeding's Prehearing Order No. 20922. Market power issues were also included in Johnson Control's Preliminary Statement of Position, dated May 7, 2004, in The Gas Company's Preliminary Statement of Position, dated May 7, 2004, and in Johnson Control's questions to HECO about HECO's possible exercise of market power in three information request to HECO, JCI-IR-105 to JCI-IR-107, dated May 24, 2004.

Q. Do you feel that there is a problem with Pacific Machinery, Johnson Controls, and/or The Gas Company withdrawing from this instant proceeding?

A. Yes. The withdrawal of Johnson Controls from the instant docket just one week before responses by HECO to their aforementioned information requests were due raise more questions about market power than has been answered. A better record could have been developed for the Commission had those former parties continue to contribute to the instant proceeding.

Additionally, the COM has been adversely affected by the withdrawal of Pacific Machinery, Johnson Controls, and The Gas Company because at the outset of the instant proceeding, the COM did not intend to focus on market power issues. We were going to rely on Pacific Machinery, Johnson Controls, and The Gas Company to address market power issues and we were going to focus our resources on additional matters directly related to the COM, such as our recommendations for a virtual power plant and on county wheeling. Due to the parties withdrawal, we have refocused our very limited resources to address market power issues because we feel that it is an issue that is critical to today's CHP market and to Hawaii's future distributed energy resources market.

Q. Are there other similar concerns to that of the NMPUC that are relevant?

A. Yes, and it relates to the issue of unfair market practices. If ratepayer-funded employees are used by the utility to compete against private energy companies, then the public utility could have an unfair competitive advantage over private energy companies. This situation is beginning to manifest itself over competition for DG business with the COM. HECO/MECO is soliciting the COM's business for landfill gas services and waste-to-energy services. HECO and MECO executives are meeting with COM officials and assessing our landfill gas and solid waste disposal needs.

The COM is concerned that it is unfair for a utility to compete against a private energy company because ratepayers fund the utility's employees, but ratepayers do not fund a private energy company's employees. The COM told HECO/MECO that we do not intend to do business directly with HECO/MECO because of this concern and because it would be inconsistent with our position on this matter in the instant proceeding. Despite what the COM told HECO/MECO at our meeting on May 5, 2004, HECO/MECO personnel appear to be continuing their assessment of the COM's landfill gas and waste-to-energy needs.

Q. Are there any other market power issues?

A. Yes. There could also be market power issues between conventional grid services and DG services. For example, a utility could use its market power to delay the deployment of DG and CHP systems to justify the development of a new central generation facility. In MECO's IRP-2 Evaluation Report, about 30 megawatts of CHP resources are forecasted for development over the next 20 years, with 25 megawatts of CHP resources being developed by MECO. Conceivably, the need for the new Waena Power Plant could be significantly deferred by accelerating the pace of CHP installations via incentives, such as DSM rebates. Deferral could allow for emerging technologies and efficiency improvements to become available that make the current design of the Waena power plant obsolete and not economically feasible. Foregoing these potential savings would be a mistake, and aggressive deployment of CHP systems in Maui could avoid this potential lost opportunity.

The Waena Power Plant could also be significantly deferred by encouraging the development of CHP systems than are larger than forecasted. The forecasted CHP systems are relatively small, in the 100-500 kW range, because they are anticipated to be designed to optimize the thermal production from the units. However, it may be more cost effective to encourage the design of relatively larger units, optimized to meet the electrical needs of the grid. For example, it may be more cost effective for MECO to incentivize via DSM rebates, the development of additional electrical capacity to thermally-optimized CHP systems than it would be for MECO to add a commensurate amount of capacity via central generation facilities.

In a fair and competitive DG marketplace, the market would optimize the timing and size of consumer DG and CHP systems. However, if HECO is allowed to control the central generation and distributed generation markets, then the opportunity to manipulate one market in favor of the other could become a problem. On Maui, the development of DG and CHP systems should take priority over the development of the Waena Power Plant.

Q. Is this market power concern consistent with HECO testimony?

A. No. In Bonnet testimony, HECO T-6 at pages 3-4, HECO states:

> The objectives of promoting combined heat and power systems ("CHP") should be to encourage energy efficiency, **to accelerate the implementation of cost-effective CHP, to provide customer choices,** and to take into account the interests of all customers. These are all utility objectives.

> Installing, owning, operating and maintaining CHP as a regulated utility will substantially further all of these objectives. (Bold emphasis added)

Q. Do you agree with this statement?

A. No, I do not agree that MECO will accelerate the CHP market on Maui. As indicated above, the utility could manipulate the CHP market on Maui to allow MECO to develop the Waena Power Plant sooner rather than later. Also, as previously stated, the incompetent or inefficient operation and maintenance of CHP systems by MECO could give the CHP market a bad image and weaken Maui's CHP market. Additionally, as I pointed out on the next page, MECO's competition in Maui's CHP market could discourage energy service companies from competing in Maui and further weaken Maui's CHP market.

Regarding HECO's assertion that they take into account the interests of all customers, Mr. Lazar addresses the fact that HECO does not take into account the interests of all customers in his rebuttal testimony.

Q. Is HECO addressing market power issues in its proposed CHP program?

A. HECO is attempting to address market power issues by altering its procurement process. In Seu testimony, HECO T-1 at page 32, HECO states:

> With the growing interest in CHP in Hawaii, the Companies became aware of the potential for some CHP projects that will

> likely require larger units than are covered by the HECO-Hess teaming agreement. Given this potential, **as well as the sensitivity expressed by some parties in this docket regarding the ability of CHP vendors to compete for projects**, the Companies felt it appropriate at this time to develop and implement a new CHP procurement process. (Emphasis added)

Q. Does this new procurement process address all market power issues?

A. No. This new procurement process may address some market power concerns of CHP vendors, such as Hawthorne Machinery Co. (the new owner of Pacific Machinery), but for energy service companies ("ESCOs") that are not equipment vendors, such as Johnson Controls and Noresco, the new procurement process by HECO does not appear to address their market power concerns. In practice, HECO's new procurement process could exacerbate market power concerns against ESCOs in that equipment vendors may be reluctant to partner with ESCOs in competition with HECO due to fear of retribution. This situation would hurt the competitiveness of ESCOs and reduce consumer choice, which is contrary to HECO's assertion that their participation in the CHP market will increase consumer choice.

Q. Are there other reasons why HECO should not participate in the consumer CHP market as a corporate entity?

A. Yes. It would be inappropriate for HECO to participate in the CHP market because from a business management perspective, large corporate entities of *established* technologies, such as HECO, are poorly suited to succeeding in *disruptive* technology markets, such as CHP.

Q. Can you first explain what are *established* and *disruptive* technologies?

A. The seminal book on *disruptive* technologies was a national bestseller titled, "The Innovator's Dilemma," authored by Clayton M. Christensen. In his book at page xviii, Christensen identifies electric utility companies as an *established* technology and describes *established* or *sustaining* technologies as follows:

> Most new technologies foster improved product performance. I call these *sustaining technologies*. Some sustaining technologies can be discontinuous our radical in character, while others are of an incremental nature. What all sustaining technologies have in common is that they improve the performance of established products, along the dimensions of performance that mainstream customers in major markets have historically valued. Most technological advances in a given industry are sustaining in character.

Mr. Christensen identifies distributed generation as a *disruptive* technology and further explains what *disruptive* technologies are, on pages xviii-xix, as follows:

> Occasionally, however, *disruptive technologies* emerge: innovations that result in *worse* product performance, at least in the near-term. Ironically, in each of the instances studied in this book, it was disruptive technology that precipitated the leading firms' failure.
>
> Disruptive technologies bring to market a very different value proposition that had been available previously...Products based on disruptive technologies are

> typically cheaper, simpler, smaller, and frequently, more convenient to use. There are many examples in addition to the personal desktop computer and discount retailing examples cited above. Small off-road motorcycles introduced in North America and Europe by Honda, Kawasaki, and Yamaha were disruptive technologies relative to the powerful, over-the-road cycles made by Harley-Davidson and BMW. Transistors were disruptive technologies relative to vacuum tubes. Health maintenance organizations were disruptive technologies to conventional health insurers. In the near future, "internet appliances" may become disruptive technologies to suppliers of personal computer hardware and software.

Q. Why are large corporate entities of *established* technologies, such as HECO, poorly suited to succeeding in *disruptive* technology markets, such as CHP?

A. At pages xxiii-xxiv of his book, Christensen states:

> With few exceptions, the only instances in which mainstream firms have successfully established a timely position in a disruptive technology were those in which the firms' managers set up an **autonomous** organization charged with building a **new and independent** business around the disruptive technology. (Emphasis added)

Christensen further states on page xxv:

> Those large established firms that have successfully seized strong positions in the new markets enabled by disruptive technologies have done so by giving responsibility to commercialize the disruptive technology to an organization whose size matched the size of the target market. Small organizations can most easily respond to the opportunities for growth in a small market.

Q. While you are on the subject of *disruptive* technologies, are there other *disruptive* technology issues pertinent to HECO's proposed CHP program?

A. Yes, and it has to do with HECO's CHP planning assumptions. I'll first start with explaining why HECO's current IRP planning process is failing to forecast market conditions, then I'll explain why the Commission should not put too much confidence in HECO's CHP projections, and finally, I'll conclude with a recommended planning strategy for disruptive technologies, such as CHP.

Q. Can you begin by explaining why HECO's current IRP planning process is failing to accurately forecast market conditions?

A. HECO's contends that they are offering CHP because of the urgent need to address Oahu's looming power capacity shortfall. In Bonnet testimony at HECO T-6, page 6, line 22, HECO states, in justifying why their CHP programs and other CHP projects should be expedited under special service or "Rule 4" contracts:

> There are several reasons, one of which is primarily applicable to HECO. As discussed by Mr. Sakuda in HECO T-3, HECO has an **urgent** need for firm generating capacity. Even with HECO's forecasted firm capacity contributions of the Companies' proposed CHP program, in combination with the energy efficiency and load management DSM program impacts, new firm capacity would be needed in 2006. (Emphasis added)

Q. What does this statement of urgency reflect, relative to IRP planning?

A. This statement of urgency reflects the same statements of urgency expressed to the COM in the past when MECO was seeking land use approvals. In a general sense, this urgency reflects the failure of HECO's and MECO's IRP processes to adequately forecast the need for central generation capacity additions. This problem becomes even more problematic with CHP and other disruptive technologies.

Q. Can you explain why planning forecasting becomes even more problematic with CHP?

A. It is more problematic because no one really knows what new disruptive markets will do, such as the CHP market. At pages xxv-xxvi of his book, Christensen states:

> In dealing with disruptive technologies leading to new markets, however, market researchers and business planners have consistently dismal records...the only thing we may know for sure when we read experts' forecasts about how large emerging markets will become is that they are wrong.

Q. Is the uncertainty associated with the forecasting of disruptive markets a reason why the Commission should not put too much confidence in HECO's CHP projections?

A. Yes. HECO uses their imperfect planning capabilities to forecast a 20-year market projection for their proposed CHP program. However, many things could change in the CHP market over the next twenty years, including the possibility that the existing CHP technologies may become obsolete and that the existing CHP market will change in response to the newer disruptive DG or CHP technologies.

Q. Can you provide an example of how existing CHP technologies could become obsolete and how new CHP or DG technologies could change the existing CHP market?

A. Let me start with an analogous situation. Computer technologies have evolved from mainframe computers, to minicomputers (i.e., mini mainframes), to office and home personal computers, to mobile notebook computers, to handheld computers, and so on. By way of comparison, power generation technologies may evolve from central station power plants, to large commercial-sized CHP, to small commercial and home DG/CHP systems, to mobile (vehicle-to-grid type) DG systems, to battery-type DG systems, and so on. In this analogy, today's CHP systems are comparable to the now obsolete minicomputers. Just as the COM's relatively large and problematic "legacy" minicomputers were made obsolete by personal computers, today's relatively large CHP systems could be made obsolete by multiple home-sized DG systems. If home-sized DG/CHP systems become commercially mainstream, then the existing CHP market could grow to a scale similar to that of the personal computer market. HECO's current strategy of trying to concurrently protect the interests of its CHP and non-CHP customers would be totally unworkable in this new market paradigm, even assuming HECO's strategy could work now.

Q. Is this a realistic situation to consider?

A. It is possible because there are other emerging disruptive DG technologies that have the potential to make internal combustion engine CHP systems obsolete, such as Stirling engine DG/CHP systems, fuel cell DG/CHP systems, and plastic photovoltaic systems.

Q. What are the some of the consequences of this type of eventuality?

A. This would not be a good situation for a customer with obsolete equipment and locked into a 20-year contract, as the terms of HECO's suspended CHP program proposes. For the Commission, this situation suggests that they should not assume that HECO's CHP ventures will be successful.

Q. If no one can reasonably forecast disruptive markets, then how can HECO plan for the CHP and other emerging DG markets?

A. Let me answer this in two parts. The first part deals with how HECO can plan for its CHP and other possible DG business ventures. Christensen recommends, as stated above, that businesses need to plan for uncertainty by a establishing small, autonomous, and responsive organization for its disruptive services. Christensen further recommends that these new organizations need to recognize market uncertainties by changing their planning focus from implementation to learning. He states on pages 180-181 of his book:

> In general, for **sustaining** technologies, plans must be made before action is taken, forecasts can be accurate, and customer inputs can be reasonably reliable. Careful planning, followed

> by aggressive execution, is the right formula for success in sustaining technology.
>
> But in **disruptive** situations, action must be taken before careful plans are made. Because much less can be known about what markets need or how large they can become, plans must serve a very different purpose: They must be plans for *learning* rather than plans for implementation. (Emphasis added)

This plan-to-learn approach suggests that "managers confronting disruptive technologies need to get out of their laboratories and focus groups and directly create knowledge about new customers and new applications through discovery-driven expeditions into the marketplace."[4] Christensen points out that markets for disruptive technologies often emerge unexpectedly and that such "discoveries often come by watching how people use products, rather than by listening to what the say."[5] This last insight discounts the emphasis HECO places on the advice it received from its prospective CHP customers.[6] Christensen's *innovator's dilemma principle* warns, "that "good" companies often begin their descent into failure by aggressively investing in the products and services that their most profitable customers want."[7]

HECO cannot guarantee that their CHP-related revenues will meet their market projections, nor can HECO guarantee that their CHP program will become successful. Therefore, the

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[4] Page 182, "The Innovator's Dilemma"

[5] Page 182, "The Innovator's Dilemma"

[6] See Seu testimony, HECO T-1, pages 22-25.

[7] Page xxx, "The Innovator's Dilemma"

Commission should consider the possibility of HECO failing in its CHP venture and protect ratepayers from such an eventuality.

Q. Can you now address the second part about how HECO can plan for the uncertainty associated with the CHP and other emerging DG markets?

A. Hawaii's CHP and other DG markets could turn out to be negligible, but they could also become pervasive. To deal with this wide range of uncertainty, HECO's IRP process should focus on creating robust plans--much more robust that have been considered in past IRP cycles. Increased use of demand-side management approaches, including demand-side generation, plus smaller capacity additions to central generation facilities may be appropriate to prevent stranded cost issues from arising. Mr. Lazar elaborates on stranded cost issues at COM-RT-2, pages 15-16.

Q. Are there other issues that you would like to address?

A. Yes. I would like to address the role of the Commission, as recommended by HECO.

Q. Which HECO recommendation would you like to start with?

A. I'll start with HECO's recommendation that the Commission should review their proposed CHP program as supply-side resources. In Bonnet testimony at HECO T-6, page

10, HECO states:

> With respect to utility offerings of CHP systems, the Commission's role is to review the application for a CHP Program as it would other supply-side planning tools under the criteria included in the IRP Framework...

Q. Do you agree with HECO's supply-side approach for CHP resources?

A. No. All privately used consumer energy technologies have customarily been treated by HECO and the utility industry as demand-side resources. HECO does not justify the purpose for addressing privately used CHP systems as a supply-side resource, nor does there appear to be any reason for treating privately used CHP systems any differently than other privately used consumer energy systems. In fact, doing so would the obscure benefit of incentivizing CHP systems with DSM rebates. It is likely that the use of DSM rebates to encourage the development of CHP systems would cost less than an equal amount central generation and power line capacity.

Q. Is there another HECO recommendation regarding the Commission's role that you would like to address?

A. Yes, and it relates to HECO's recommendation to approve its CHP program and tariff filing and/or individual CHP Rule 4 filings. In Bonnet testimony at HECO T-6, page 4, HECO states:

> If the electric utility is allowed to participate in the CHP market as a regulated entity, the Commission **must** approve the Companies' Schedule CHP tariff filing, and/or individual CHP Rule 4 filings, and the Commission, with input from the Consumer Advocate, has the authority to regulate the Companies to ensure that the interests of all customers are taken into consideration. (Emphasis added)

Q. Do you agree with this statement?

A. No. The Commission does <u>not</u> need to approve HECO's suspended CHP application, even if the Commission allows HECO to participate in the CHP market as a regulated entity, because some of the provisions of the application may not be appropriate. This position also applies to any CHP Rule 4 filing. However, it is appropriate to conclude that the CHP Rule 4 filings be approved after the Commission determines whether HECO can participate in the CHP market as a regulated entity because not approving the CHP Rule 4 filings would pre-empt the Commission from the considerations being developed in the instant proceeding. The County of Maui recommends that if HECO files CHP Rule 4 filings before the Commission who decides on the instant proceeding, then the Commission should suspend or deny those filings, or at the very least, require HECO to publicly notice the filings and to notify the parties in this proceeding.

Q. Does this conclude your rebuttal testimony?

A. I will conclude by stating my silence on other matters in HECO's testimonies does not mean that the COM agrees with all of HECO's other statements and positions. I have not addressed other issues due to limitations on my time and resources and Mr. Lazar has not addressed other issues due to my limited ability to fund his services.

PMA ONLINE MAGAZINE

STATELINE by Robert Olson

May 1999

LOUISIANA PUBLIC SERVICE COMMISSION DECLEARE COGENERATION FACILITY JOINTLY OWNED BY A UTILITY AFFILIATE AND A MANUFACTURING COMPANY NOT A PUBLIC UTILITY

by Robert Olson -- Brown, Olson and Wilson, P.C.

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On April 21, 1999, the Louisiana Public Service Commission (PSC) unanimously determined that a cogeneration facility whose power would be consumed by an owner-manufacturing company and would be sold at wholesale is not an electric public utility under Louisiana law, and not otherwise subject to regulation by the PSC as an electric public utility. The cogeneration facility is a combined cycle project, and the steam produced could be sold to third parties. The joint owners are PPG Industries, Inc. (PPG), a manufacturer having a chemical plant at the site of the proposed cogeneration facility, and Entergy Power (Entergy), a non-regulated subsidiary of Entergy Corporation. Factors considered by the PSC in its decision included the fact that each owner holds a fifty percent interest in the facility, which mirrors capacity entitlements for each owner; the fact that PPG would use a portion of its capacity entitlement for its on-site chemical plant; the fact that PPG would operate the facility; and the fact that there would be no retail sales of the energy. The PSC declined to regulate the production and sale of steam generated at the facility.

Under Louisiana law, an "electric public utility" is defined as "any person furnishing electric service within the State of Louisiana." Persons not primarily engaged in the generation, transmission, distribution, and/or sale of electricity who own, lease, or operate an electric generation facility are exempted from this general rule provided such persons consume all of the energy generated by the facility for their own use at the site of generation, sell all of the energy generated to an electric public utility, or combine self-consumption with sale to a public utility.

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In the petition to the PSC requesting a declaration as to the regulated status of the facility, the owners described the plan related to the proposed facility. The PSC specifically limited its order to these factual representations. The direct owner of the facility will be RS Cogen, with PPG and Entergy each owning fifty percent of RS Cogen, and each entitled to fifty percent of the electric capacity of the facility. Each owner is committed to pay for its capacity with mirror demand charges. While Entergy is a non-regulated company, it is affiliated with Entergy Gulf States, Inc. (EGS), which is an electric utility providing service in the area surrounding the site of the facility, by virtue of the fact that each is owned by Entergy Corporation, a public utility holding company. However, Entergy's relevant activities are independent and segregated from the regulated activities of EGS.

PPG will use its capacity for its on-site chemicals plant and/or will sell its capacity in the wholesale power market. The capacity to which Entergy is entitled will be sold to Entergy Power Marketing Corporation (EPMC), a wholesale power marketer affiliated with Entergy. EPMC will only sell its capacity entitlement in the wholesale power market. The owners will apply for the facility to achieve the status of a "Qualifying Facility" under the Public Utility Regulatory Policies Act (PURPA). RS Cogen will sell the steam generated by the facility to PPG and possibly third parties pursuant to the requirements of the PURPA. The owners represented that no retail electric service would be provided by the facility and that no utilities or ratepayers will become obligated for any of the costs associated with the facility.

Because the facility would not be providing retail electric service to the public, and because the facility would have no captive customers and not subject ratepayers or utilities to risk, the PSC found the owners do not provide electric service to the public and are therefore not subject to the jurisdiction of the PSC.

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The PSC additionally found the facility falls within the exemption provision of "electric public utilities" under Louisiana law. The PSC found all three owners to be owners, lessees, or operators of the generating facility on the basis that RS Cogen is the direct owner, PPG is an indirect owner and the operator of the facility, and that Entergy is an indirect owner. The PSC also found that no owner is primarily engaged in the generation, transmission, distribution and/or sale of electricity. The PSC specifically noted that a greater than fifty percent equity interest in the facility by Entergy would meet this requirement, but a fifty percent equity interest does not. Even though Entergy is neither a utility nor a holding company, because it is held by a electric utility holding company, it is considered engaged in the generation, transmission, distribution and/or sale of electricity.

The PSC also found the self-consumption and/or wholesale consumption requirement for the electric public utility exemption to be present. Because PPG is an owner/operator of fifty percent of the facility and because that ownership interest is equivalent to its entitlement to fifty percent of the capacity, the PSC found that PPG will not be buying power from the facility, but instead will be consuming energy for its own use. The PSC further determined that the sale of power in the electric wholesale market by PPG and Entergy is not subject to state regulation because the wholesale sales would fall under the jurisdiction of the Federal Energy Regulatory Commission (FERC). Even though states have the responsibility to implement FERC's regulations pertaining to wholesale power sales by qualifying facilities under PURPA and the PSC did issue such an order implementing the regulations, the PSC found that a wholesale sale between PPG and an electric utility would not subject PPG to state regulation where the sales are an integrated part of the qualifying facility. However, the PSC stated the order does not affect its ability to regulate PPG or RS Cogen as a customer or supplier to EGS, including sales of excess energy under PURPA. The PSC similarly found that the transfer of Entergy's fifty percent capacity to EPMC constitutes a wholesale sale of power of a qualifying facility which is not subject to state regulation.

The PSC declined to regulate the production and sale of steam generated by the facility, stating it has not historically done so and does not intend to change that policy now. The PSC conditioned the order on the facility remaining a "qualifying facility" under PURPA and asserted the order does not affect its regulatory power over the owners in the event retail competition is approved in Louisiana. The PSC also stated the order does not affect its avoided cost regulations.

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IN THE SUPREME COURT OF THE STATE OF NEW MEXICO

Opinion Number: 1998-NMSC-017

Filing Date: March 18, 1998

Docket No. 24,007

IN THE MATTER OF THE APPLICATION OF PNM ELECTRIC SERVICES, A DIVISION OF PUBLIC SERVICE COMPANY OF NEW MEXICO, FOR APPROVAL TO PROVIDE CERTAIN OPTIONAL SERVICES ON AN EXPERIMENTAL BASIS,

PNM ELECTRIC SERVICES, a division of Public Service Company of New Mexico,

Appellant,

v.

NEW MEXICO PUBLIC UTILITY COMMISSION,

Appellee,

and

NEW MEXICO INDUSTRIAL ENERGY CONSUMERS and ATTORNEY GENERAL OF THE STATE OF NEW MEXICO,

Intervenors.

consolidated with:

Docket No. 24,008

IN THE MATTER OF THE APPLICATION OF PNM GAS SERVICES, A DIVISION OF PUBLIC SERVICE COMPANY OF NEW MEXICO, FOR APPROVAL TO PROVIDE CERTAIN OPTIONAL UTILITY SERVICES ON AN EXPERIMENTAL BASIS,

PNM GAS SERVICES, a division of Public Service Company of New Mexico,

Appellant,

v.

NEW MEXICO PUBLIC UTILITY COMMISSION,

Appellee,

and

EXHIBIT COM-R-102

NEW MEXICO INDUSTRIAL ENERGY CONSUMERS,

Intervenors.

APPEAL FROM THE NEW MEXICO PUBLIC UTILITY COMMISSION

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OPINION

BACA, Justice

{1} In these consolidated appeals, Appellant Public Service Company of New Mexico (PNM), pursuant to Rule 12-102(A) NMRA 1997, appeals decisions of the Appellee New Mexico Public Utility Commission (Commission) in Case Nos. 2655 and 2668. In its decisions, the Commission denied the applications of PNM to institute gas and electric "optional service programs." This Court now considers the propriety of the

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application denials. After careful review, we uphold the Commission decisions denying PNM's applications.

I.

(2) In Commission Case 2655, PNM Gas Services[1] filed an application with the Commission seeking approval, on an experimental basis, of a new tariff that would allow PNM to offer certain gas optional services to retail customers. Specifically, PNM sought approval for a new food service management program for its business customers who operate food service facilities.

(3) Similarly, in Commission Case 2668, PNM Electric Services[2] petitioned for approval of a new tariff which would allow PNM, on an experimental basis, to offer electric optional services to retail electric customers. These services included four basic programs: 1) transient voltage surge suppression; 2) maintenance and repair services; 3) energy information services; and 4) power quality solutions.

(4) Participation in these programs was optional in that each eligible customer would have the choice of whether or not to contract with PNM for the service. Also, neither of these services were considered essential components of PNM's Commission-regulated gas or electric utility services. PNM contemplated that either PNM utility personnel or contractors retained by PNM would provide the optional services. PNM sought authority to offer the optional services under tariffed pricing provisions that were flexible. This would allow PNM to adjust prices between a floor and a ceiling price. The floor price would be PNM's incremental cost of providing the service and the ceiling price would be a multiple of the floor price intended to reflect the upper range of the estimated market value of the service.

(5) PNM Gas Services presented its optional service program before a Commission hearing examiner on December 12, 1995. Although the hearing examiner recommended approval of the tariffs for PNM Gas Services' optional service programs, on May 30, 1996, the Commission entered its final order on the application, rejecting most elements of the petition. A Commission hearing examiner also held a hearing addressing

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[1]PNM Gas Services is an unincorporated division of PNM providing gas services to PNM's New Mexico retail utility customers.

[2]PNM Electric Services is also an unincorporated division of PNM.

PNM Electric Services' application on March 4, 1996. The hearing examiner recommended against approving the tariffs proposed by PNM Electric Services due to a conflict with an earlier stipulation by PNM. Eventually, the Commission rendered a final order regarding this petition on August 5, 1996, rejecting most elements of PNM Electric Services' proposal as well.

(6) PNM Gas and Electric Services delineated the following goals for the optional service programs: to continue to be responsive to customer needs by offering services that are complementary to the existing utility businesses; to improve PNM's relations with its customers and hence its competitiveness; to improve safety and provide choice in the marketplace; and to build upon the core business of providing utility services by offering new energy-related options to eligible customers who would enter into contracts with PNM for the optional services.

(7) However, the Commission responded with similar reason in Cases 2655 and 2668 for rejecting the optional service plans. Primarily, the Commission stated that the optional services consisted of "utility-related non-utility services." As such, the Commission held that it would be inappropriate to treat these non-utility services as tariffed utility services under the New Mexico Public Utility Act, NMSA 1978, §§ 62-3-1 to 62-3-5 (1967, as amended through 1996). Therefore, the Commission disapproved of PNM's applications and proposed rates. The Commission reasoned that treating optional service programs as tariffed utility services created several possible problems, including a concern about real or potential cross-subsidies, potential liabilities, and claims of antitrust or unfair trade practices.

(8) While the Commission rejected the applications to carry out these optional service plans as utility-related programs, the Commission suggested in its final orders that an unregulated entity, such as a PNM corporate subsidiary, still might implement and offer the optional service programs. The Commission informed PNM that it could reapply for approval to offer its proposed optional services as non-utility services, possibly by seeking implementation of these programs through a subsidiary. However, the Commission noted that PNM would have to make a proper filing as required by the Public Utility Act and Commission Rule 450, which require prior Commission approval before a utility can form a subsidiary or financially assist a non-utility activity.

{9} Upon denial of PNM's applications for diversification, this Court is asked to review: 1) whether the Commission had jurisdiction to deny PNM's applications; and 2) whether the Commission, by denying the application, unduly intruded upon matters of management prerogative. We hold that the Commission acted within its statutorily granted jurisdiction in denying PNM's applications and conclude that the denials did not constitute an impermissible intrusion upon management prerogative.

II.

{10} Statutes create administrative agencies, and agencies are limited to the power and authority that is expressly granted and necessarily implied by statute. See New Mexico Elec. Serv. Co. v. New Mexico Pub. Serv. Comm'n, 81 N.M. 683, 684, 472 P.2d 648, 649 (1970). Where a question of Commission jurisdiction is involved, courts afford little deference to the agency's determination of its own jurisdiction. See United Water New Mexico, Inc. v. New Mexico Pub. Util. Comm'n, 121 N.M. 272, 274-275, 910 P.2d 906, 908-09 (1996).

{11} However, when the Commission acts within its jurisdiction, this Court may not substitute its judgment for that of the agency, See Public Serv. Co. v. New Mexico Pub. Serv. Comm'n, 92 N.M. 721, 722, 594 P.2d 1177, 1178 (1979). We must view the evidence in the light most favorable to the Commission's decision. See New Mexico Indus. Energy Consumers v. New Mexico Pub. Serv. Comm'n, 104 N.M. 565, 570, 725 P.2d 244, 249 (1986). The burden is on the party appealing to demonstrate that the order appealed from is unreasonable or unlawful. *See* NMSA 1978, § 62-11-4 (1965); see also Maestas v. New Mexico Pub. Serv. Comm'n, 85 N.M. 571, 574, 514 P.2d 847, 850 (1973). The issues we resolve are: 1) whether the action of the administrative body was within its authority; 2) whether the order was supported by substantial evidence, and; 3) whether the administrative body acted fraudulently, arbitrarily, or capriciously. Id. at 574, 514 P.2d at 850 (quoting Llano, Inc. v. Southern Union Gas. Co., 75 N.M. 7, 11-12, 399 P.2d 646, 649 (1964)).

III.

{12} We first review whether the Commission acted within its jurisdiction when it rejected PNM's applications. In this appeal, PNM characterizes the Commission's orders as exercising jurisdiction over its non-utility activities and contends that under NMSA 1978, § 62-3-4(B) (1992), the Commission lacks such jurisdiction. We disagree with PNM's characterization of the issue and conclude that the Commission's orders did not constitute interference with PNM's non-utility activities.

{13} Because the Commission acted pursuant to its power to ensure that utilities provide fair and just rates, the orders issued in this case were permissible. It is undisputed that PNM is a public utility. See NMSA 1978, § 62-3-3(G) (1996). As a public utility, PNM has a duty to provide adequate service at just and reasonable rates. See NMSA 1978, §§ 62-8-1 to 62-8-2 (1941). The Commission has "general and exclusive power and jurisdiction to regulate and supervise every public utility in respect to its rates[,] . . . service[s,] . . . and . . . securities . . . and to do all things necessary and convenient in the exercise of its power and jurisdiction." *See* NMSA 1978, § 62-6-4(A) (1996). Furthermore, it is the stated policy of New Mexico that the public interest and the interest of consumers and investors require the regulation of utilities so that service is available at just and fair rates. NMSA 1978, § 62-3-1(B) (1967).

{14} New Mexico courts recognize this expansive regulatory power, broadly and liberally construing the Public Utilities Act to effect the Legislature's articulated policies. See Griffith v. New Mexico Pub. Serv. Comm'n, 86 N.M. 113, 520 P.2d 269 (1974); see also Hogue v. Superior Utils., 53 N.M. 452, 456, 210 P.2d 938, 941 (1949) (stating that "[e]xperience has taught that public utility companies cannot be allowed to contract indebtedness at will and run their affairs as it may please them, and when the legislature passed the 1941 Act for their control[,] it gave the Public Service Commission broad powers over them.").

{15} In the PNM Gas Services case, the Commission officer heard evidence regarding complications potentially arising out of the implementation of PNM Gas Services' optional service program. Witnesses addressed the issues of cross-subsidies and potential cross-subsidies, liability from lawsuits, and antitrust immunity issues. As noted in the hearing officer's recommended decision, PNM Gas Services designed the proposed food service maintenance program to utilize utility assets. Witnesses testified that the use of existing personnel and facilities to perform optional services raised substantial questions about the utility's current utilization of employees and assets. It also created concerns about PNM Gas Services' potential for double recovery. The Commission's final order indicates that it considered PNM Gas Services' assertion that detailed accounting would provide sufficient protections to

ratepayers, but the Commission did not find that such safeguards would suffice.

{16} The hearing officer noted in his recommended decision that PNM Gas Services' proposed services might expose PNM to liability from lawsuits. The Commission indicated that it carefully considered PNM Gas Services' contention that the liability arising from the provision of optional service is substantially the same for those associated with the delivery of core utility service. However, the Commission decided that the liabilities at issue in the case were new, additional liabilities arising from the proposed provision of non-essential services. The Commission also noted that losses associated with such liability could harm PNM and ratepayers in several ways: causing PNM to cut utility costs through delayed maintenance; laying off employees; or not making necessary capital investments. Finally, the Commission also expressed concern that if it granted PNM Gas Services' request to regulate such non-utility activities, the Commission would be providing PNM's non-utility activities immunity from antitrust claims under the "state action" doctrine. See generally Parker v. Brown, 317 U.S. 341, 351 (1943) (holding that the Sherman Act was not intended "to restrain state action or official action directed by a state"). For these reasons, the Commission rejected PNM Gas Services' proposal. The Commission noted similar concerns in its order regarding PNM Electric Services' petition and rejected it on substantially similar grounds.

{17} We conclude that the Commission acted within its jurisdiction and within the broad authority granted to it by the Legislature. While PNM attempts to characterize the Commission's action as regulation of its non-utility ventures, the Commission's orders do not regulate the prices or services being offered, nor is the Commission preventing PNM from providing the services. Instead, the Commission informed PNM that it may not engage in the proposed non-utility businesses unless it establishes them as corporate subsidiaries. By instituting these conditions, the Commission acted as the statute requires - protecting PNM and its ratepayers from the potential adverse consequences that might arise if PNM implemented the optional service plans.

{18} Hence, the Commission's authority to act in this case does not come from its exercise of jurisdiction over non-utility activities but, instead, from its statutory obligation to ensure that PNM does not engage in activities that could harm PNM's ability to set just and reasonable rates. Acting within this context, the Commission was well within its authority to require that any establishment of the proposed optional service programs be carried out as unregulated corporate subsidiaries in order to obtain Commission approval of the optional services.

{19} PNM argues that NMSA 1978, § 62-3-4 (1992) limits the broad authority of the Commission. Section 62-3-4 states that "[t]he business of any public utility other than of the character defined in Subsection G of Section 62-3-3 NMSA 1978 is not subject to the provisions of the Public Utility Act, as amended." We need not address whether this provision generally limits the power of the Commission over the non-utility activities of a public utility that are wholly unrelated to its public utility functions. Even assuming such a limitation, it is clear that PNM's optional services are of the character defined in Section 62-3-3(G). The Commission's jurisdiction extends to the rates and services of a public utility. Section 62-6-4(A). This grant of jurisdiction includes every "practice [or] act" of public utilities "in any way relating" to the rates and services of the utility. Section 62-3-3(H) (defining "rate"), (I) (defining "service"). The Commission found that the optional services are "utility-related," and PNM concedes that the optional services "are directly related to the provision of traditional gas and electric utility service." [Reply Br. at 5.] We conclude that the optional services are within the scope of Section 62-3-3(G) and, therefore, within the jurisdiction of the Commission.[3]

IV.

A.

{20} PNM also argues that the Commission's orders constituted an infringement upon management prerogative. PNM relies on authority that articulates a principle that regulatory commissions are limited in their ability to inject themselves into the internal management affairs of a public utility. However, we believe that the same broad authority that permits the Commission to act to ensure that rates are fair, just, and reasonable also answers PNM's contentions regarding management prerogative.

{21} We recognize that the Commission's authority to inject itself in the internal management of a public utility is limited. See, e.g., Missouri ex rel. Southwestern Bell Tel. Co. v. Public Serv. Comm'n, 262 U.S. 276, 288-89 (1923);

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[3] We do not find it necessary to address the parties' arguments concerning Section 62-3-3(K) since other provisions of the statute answer the jurisdictional questions raised.

Public Serv. Co. v. State ex rel. Corp. Comm'n, 918 P.2d 733, 739-40 (Okla. 1996); Duquesne Light Co. v. Pennsylvania Pub. Util. Comm'n, 507 A.2d 1274, 1278 (Pa. Commw. Ct. 1986). However, we reject this rationale as a grounds for reversal. The "invasion of management" prohibition upon which PNM relies has waned. General Tel. Co. v. Public Utils. Comm'n, 670 P.2d 349, 353-56 (Cal. 1983) (en banc) (describing the history of the "invasion of management" rationale in California and rejecting its application on specific facts). Furthermore, courts have permitted commissions substantial latitude in protecting the public. See Arizona Corp. Comm'n v. State ex rel. Woods, 830 P.2d 807, 818 (Ariz. 1992) (en banc) ("The Commission must certainly be given the power to prevent a public utility corporation from engaging in transactions that will so adversely affect its financial position that the ratepayers will have to make good the losses . . . ."). Even some of PNM's cited authority notes that commissions are generally empowered to act in areas seemingly reserved to management prerogative where the regulated action is "impressed with public interest." Public Serv. Co. v. State ex rel. Corp. Comm'n, 918 P.2d at 739 (quoting Missouri Pac. R.R. Co. v. Corporation Comm'n, 672 P.2d 44, 44 (Okla. 1983)). PNM's additional cited authority fails to undermine this proposition.

{22} Our statute limits the authority of the Commission to matters of public concern, see Southwestern Pub. Serv. Co. v. Artesia Alfalfa Growers' Ass'n, 67 N.M. 108, 117-18, 353 P.2d 62, 68-69 (1960), and prohibits unreasonable and unlawful action by the Commission, see NMSA 1978, § 62-11-5 (1982). We understand this limit of authority as incorporating current notions of management prerogative. Cf. Mountain States Tel. & Tel. Co. v. Public Serv. Comm'n, 745 P.2d 563, 568-70 (Wyo. 1987) (resolving issue of utility management prerogative as a matter of statutory authority). Thus, we need not separately address the issue of management prerogative, and, instead, we return to the three issues identified at the outset: 1) whether the Commission's decision was within its statutory grant of authority; 2) whether the Commission's decision was arbitrary or capricious; and 3) whether the Commission's decision is supported by substantial evidence.

B.

{23} The Commission's decision in this case was premised on substantial evidence in the record. Substantial evidence is relevant evidence that a reasonable person might accept as adequate to support a conclusion. See New Mexico Industrial Energy Consumers, 104 N.M. at 570, 725 P.2d at 249.

Substantial evidence concerning PNM's optional service plans and the potential risks posed to PNM's ability to guarantee just and fair rates was presented. In such instances, we will not substitute our judgment for that of the Commission. See Public Serv. Co., 92 N.M. at 722, 594 P.2d at 1178.

C.

{24} Arbitrary and capricious acts are those that may be considered wilful and unreasonable, without consideration, and in disregard of the facts and circumstances. See McDaniel v. New Mexico Bd. of Med. Exam'rs, 86 N.M. 447, 449, 525 P.2d 374, 376 (1974) (citing Smith v. Hollenbeck, 294 P.2d 921 (Wash. 1956)). The record clearly indicates that the Commission carefully considered the facts and its available options before issuing its order. As noted in Section III of this Opinion, the Commission considered the policy concerns created by the proposed implementation of the optional service programs. The record indicates that the Commission's rationale in requiring use of corporate subsidiaries was firmly rooted in the public interest and in concern that PNM be able to provide service at just and reasonable rates. Furthermore, the record also demonstrates that before arriving at its decision, the Commission carefully considered the available options that might address its concerns. It concluded that the most appropriate solution was to require that the proposed optional service programs be conducted, if at all, through corporate subsidiaries. Hence, the Commission's actions were narrowly tailored to address concerns of the public interest, and nothing in the record suggests that the Commission acted arbitrarily or capriciously. Thus, we defer to the expertise of the Commission in its findings. See Attorney Gen. v. New Mexico Pub. Serv. Comm'n, 111 N.M. 636, 642, 808 P.2d 606, 612 (1991).

V.

{25} In sum, the Commission possesses the authority to issue the orders that were challenged in this case. The Commission acted pursuant to its power to ensure just and reasonable rates and to require adequate service. Furthermore, the record indicates that the Commission's actions were narrowly tailored and designed to address ratepayer concerns while minimizing interference with PNM's management prerogatives. For these reasons, we affirm.

{26} **IT IS SO ORDERED.**

JOSEPH F. BACA, Justice

EXHIBIT COM-R-102

WE CONCUR:

GENE E. FRANCHINI, Chief Justice

PAMELA B. MINZNER, Justice

PATRICIO M. SERNA, Justice

DAN A. McKINNON, III, Justice

A major technical interconnection issue was the requirement for additional protective relays. The inverter equipment already supplied protective relays including ground fault protection relays, under/over voltage protection, and under/over frequency protection. Thus, if there were any kind of fault on either the utility side or the solar site side, the inverter could ensure that the site would automatically shut down.

The utility initially requested installation of additional protective relay equipment that cost between $25,000 and $35,000. This additional protective relay equipment was redundant to the protective relays already provided with the inverter. After negotiations, the utility ultimately agreed that this additional equipment was not needed.

Distributed Generator's Proposed Solutions

The project developer was working closely with the utility to resolve the technical and procedural interconnect issues. The developer was still hoping to negotiate a reasonable solution to the request for redundant relays.

In the project developer's opinion, identifying the right person at the utility was critical and maintaining contact with the individual was also important. If the project developer and the utility had not worked together, the project would have been more difficult and could have been delayed.

Case #14 — 120-kW Propane Gas Reciprocating Engine for Base Load Service at Hospital

Technology/size	Propane Gas Recip Cogen for Absorption Chiller and Hot Water Heating/ 120 kW
Interconnected	No
Major Barrier	Technical—Safety Equipment Business Practices—Discount Tariffs
Barrier-Related Costs	$7,000
Back-up Power Costs	None

Background

A developer was installing a 120-kW propane gas reciprocating engine in a remote area where natural gas was not available and the cost of demand and energy quite high. The project was being installed on the low voltage side of a hospital's own 12.4-kV to 120/2080-volt step-down transformer. This facility was being charged an energy charge of 8.69 cents/kWh and a demand charge of $5.75/kW-month. In addition, because the hospital had a high hot-water bill, it was a good candidate for a cogeneration project. The hospital's monthly electric bill was typically around $12,500/month and the gas bill was $4,700/month. Part of the electric load included chillers that needed to be replaced.
The project was intended to operate as a base load unit. In addition to supplying 120 kW of electric power, the project will also supply hot water to a new absorption chiller and for hot water heating. The project allows for the elimination of a 5-ton heat pump that has been used for heating the swimming pool. With the new installation, the swimming pool can be heated at night when the absorption chiller is not needed. The proposed project will maintain this temperature with only 3 hours of recovered heat a day transferred to the pool.

Technical Barriers

Many of the barriers associated with the project have been technical issues that required resolution between the utility and the developer. The project was scheduled for completion on May 1, 1999. As of September 27, 1999, even though the inspection was complete, the developer had not received a letter from the utility allowing the unit to run for purposes other than testing. These technical barriers include the following:

- The utility requested a lightening arrestor that costs $20,000. The developer is still negotiating with the utility and the issue has not yet been resolved. The lightening arrestor is for the underground 12.4-KV primary voltage line. No other location in the state has this equipment installed at this time.

- The utility requested that a breaker rated for 2000 amps be installed on the low voltage side of the transformer. The building already had 2 separate 1600-amp breakers (for two separate feeders). The equipment specified has not been made since 1982, and GE quoted a cost of $40,000 and six months lead time. This was pointed out to the utility, and the requirement was dropped.

- The utility stated that the high voltage feed was not grounded, and an inspection was required to prove that a high-voltage ground existed. Scheduling the inspection took one month.

The utility requested a reverse power relay, even though this installation is an induction generator that requires an outside source of voltage to operate. The original relay specified by the utility was not appropriate for the installation, and General Electric (supplier of the relay) would not warranty it in the application. The utility agreed to a different relay as specified by General Electric; however, this process took an additional eight weeks. The utility required synchronizing equipment and parallel operation monitoring for the induction generator that has a reverse power relay installed that shuts down the entire cogeneration plant. This cost was over $6,000 for equipment that the developer argued was unneeded.

Regulatory Barriers

Back-up Charges

When the project was proposed, the utility had no standby charges in their tariff. During the project development, the utility requested a $1,200/kW-year standby charge from the PUC. However, the request to the PUC was rejected on the basis that 120 kW could not affect the grid.

Business Practice Barriers

Discount Tariff and Anti-Cogeneration Campaign

The utility has openly discouraged its customers from installing cogeneration facilities and switching to cheaper more-efficient power. In a publication sent to all customers, the utility stated that cogeneration is inefficient and expensive. The publication points out "the heat produced by the cogeneration system cannot be fully utilized by the facility that it serves. Any wasted thermal energy is a lost opportunity for cogeneration units." The publication did not point out that without cogeneration (with the traditional generating station) all the thermal energy is lost.

The utility's publication specifically targeted the addition of absorption chillers to a cogeneration installation. A developer had recently been promoting this technology and had 20 installations in the utility's territory. The publication stated, "The absorption chiller is being added in an attempt to use more of the thermal energy available from the fuel to improve cogeneration system performance. In the past, absorption chillers have not been used because of their very high energy consumption and poor efficiency. For example, a typical absorption chiller requires 1 Btu of energy to create 1-1.2 Btu of cooling. In contrast, a high efficiency electric chiller, such as those qualifying for utility rebates, provides 7 Btu's of cooling energy for every Btu of energy supplied to the chiller." The publication again did not mention that the absorption chiller uses 1 Btu of energy from waste heat that would not be used except in the chiller application. On the other hand, the Btu's used for the electric chiller must be generated by the utility and paid for by the customer.

The utility also stated that the economics of cogeneration were difficult because of the lack of availability of natural gas. Yet, the utility was offering discounts to customers that did not install their own generation source. The utility had introduced a tariff reduction of 11.77 percent for customers who seriously considered cogeneration but opted to stay with the utility. The tariff required the customer to conduct economic analyses showing the savings associated with cogeneration. In addition, the customer must provide cost estimates from vendors showing the cost savings.

At the same time, the utility did have programs to support renewable energy. They had a rebate program for residential solar hot water heaters and an educational program to install photovoltaic systems (PV) in schools. These installations were installed on the customer's side of the meter; thus, the energy generated by the PV project would only be available to the school.

Estimated Costs

The costs associated with this project were primarily associated with the additional equipment required. The additional costs included $7,000 for what the developer believed to be unnecessary equipment and possibly another $20,000, still in negotiation with the utility.

Distributed Generator's Proposed Solutions

In this case, the PUC prohibited the utility from imposing a back-up tariff that would have stopped the project. This case shows that barriers can be removed with regulation. On the other hand, the PUC has also continued to allow incentive tariffs for customers that stayed with the utility instead of installing more efficient cogeneration. (See discussion of economic or uneconomic bypass at notes 44 and 58 on pages 23 and 28.)

The cogeneration plant developer believed that it had met or exceeded all interconnection requirements by the utility, but the utility had not yet allowed the unit to go on line at full output. The plant could operate 95-percent output for testing and documentation. The utility did not provide a schedule when the unit would be allowed to operate.

Case # 15 — 75-kW Natural Gas Microturbine in California

Technology/size	Natural Gas Microturbine/ 75 kW
Interconnected	No
Major Barrier	Regulatory—Utility Prohibition to Interconnection
Barrier-Related Costs	$50,000
Back-up Power Costs	Not Known

Background

In this case, an oil and gas producer with a well located at a public school in California sought to install a 75-kW microturbine and had been unable to interconnect the facility with the local utility under acceptable terms. The principal obstacle was a fundamental disagreement regarding the utility's legal obligation to interconnect a non-utility-owned generating facility, which did not meet the legal definition of a QF under the federal PURPA statute.

The project owner had a producing oil well located on the school property. The well also produced natural gas, which the school had been processing and delivering for sale into a natural gas pipeline. The producer hired a consultant to explore the possibility of capturing additional value from the natural gas by using it to fuel an on-site electric generating facility to power the oil derrick and to use residual heat from the generating facility for space and water heating at the school.

The energy project developer contracted with the school to install a 75-kW microturbine on the school property, in part to allow both the project developer and the manufacturer to gain operational experience with this relatively new product. The project developer planned to operate the facility, with the entire output of the microturbine going directly to meet the oil derrick's electrical loads. Because the derrick's electricity demand of approximately 1,000 kW is larger than the microturbine's 75-kW generating capacity, none of the electricity generated would be delivered to the utility. Assuming that the microturbine was operating at a 95-percent capacity factor, it would produce approximately 52,000 kWh per month, with a value (assuming retail prices of $0.10 per kWh) of approximately $5,200 per month.

The project was installed in July 1999 and operated briefly to ensure operational readiness. The project was then shut down because the project developer had been unable to negotiate an acceptable interconnection agreement with the local utility. As of September 1999, the project remained stalled because no agreement had been reached.

Regulatory Barriers

Utility Prohibition to Interconnection

The project developer stated that recent changes in California law opened the way for the interconnection of non-QF as well as QF generation and that the utility publicly had stated there was "no problem" with interconnecting to the utility. However, the utility refused to interconnect, arguing that it had no legal obligation to do so. The utility interpreted its obligations to interconnect non-utility-owned generating facilities as being limited under the federal PURPA statute to QFs, which included facilities powered by renewable resources such as sun, wind, and water and cogeneration facilities. Because this microturbine did not meet these criteria, the utility's position was that it had no obligation to interconnect the facility to operate in parallel with the utility.

COM-RT-2

Before the Hawaii Public Utilities Commission

Rebuttal Testimony of
Jim Lazar, Consulting Economist

On Behalf of
County of Maui

Docket No. 03-0371

October 22, 2004

Exhibit COM-RT-2
Rebuttal Testimony of Jim Lazar
On Behalf Of
County of Maui

Q. Are you the same Jim Lazar who previously submitted direct testimony and exhibits on behalf of the County of Maui?

A. Yes.

Q. What is the purpose of your rebuttal evidence in this proceeding?

A. I respond to the testimony submitted by HECO and by the Consumer Advocate on several topics. These include:

- **Market Power** issues associated with utility involvement in CHP, where I demonstrate that HECO would have a very dominant market position under its proposal.

- **Lost Revenue** issues raised by HECO, which I find to be a smokescreen under current circumstances, where avoided marginal costs greatly exceeded embedded cost based tariff rates.

- **Standby Rate** issues, where I propose a form of rate design previously approved by the New York Public Service Commission that I believe constructively addresses the concerns about unbundling raised by the Consumer Advocate's witness, and will result in rates that are fair to the Companies and attractive to potential DG customers. I advocate that these types of standby rates be available on a non-discriminatory basis to all self-generation customers, whether they own their own facilities or buy CHP service from the utility (if that is allowed).

- **Time-of-Use** rate issues, where I respond to Ms. Seese's assertion that the current load factor block rates are a proxy for time-of-use rates, and I develop and propose the substitution of TOU rates for the current load factor block rates.

Q. Are you sponsoring rebuttal exhibits with this testimony?

A. Yes. I am sponsoring the following exhibits:

COM-R-201	Market Power Index Calculation
COM-R-202	Lost Revenue Imputation
COM-R-203	Standby Rate Design Development
COM-R-204	Time Of Use Rates As Alternative to Load Factor Blocks

Q. Please begin with the market power issues. What is "market power" and how is it traditionally measured?

A. Market power exists when one supplier has a sufficient dominance of the market for any particular good or service that they can influence the price or characteristics of the marketplace. In the electric power area, market power was determined to be a primary cause of the west coast energy crisis of 2000-2001. A decline in power from hydro resources due to a drought created a situation where individual power plant owners could cause a market price increase by withholding supplies – and reportedly did so in order to increase their own profitability. By definition, if one supplier can affect the market price, a non-competitive situation is present.

Market power is often measured by what is known as the Herfindahl-Hirschman Index, or HHI, which turns market shares into a measure of market concentration.

Q. What are the market power issues raised by the CA and HECO testimony?

A. Both HECO and the CA recommend that the utility be allowed to offer CHP service as a regulated utility service. There is reason to believe that this would lead to HECO being in a dominant position, and able to exert market power. This is a principal reason that Mr. Kobayashi is recommending that the utility NOT be permitted to offer this service.

Q. What market share does HECO estimate it would have if its CHP proposal were accepted?

A. HECO estimates in Exhibit A to its CHP application that it would have the following market shares on each of the islands:

Island	HECO-Owned	Total Systems	HECO %
Oahu	72	97	74%
Hawaii	68	92	74%
Maui	76	99	77%

Q. How does one calculate the HHI from the data supplied by HECO?

A. The HHI is computed as the sum of the squares of the market share of each market participant. If one participant has 100% of the market, the HHI is 10,000, a completely concentrated market. If each of ten participants has 105 of the market, the index is ten times ten-squared, or 1,000.

Q. At what point does a market become unacceptably concentrated?

A. According to FERC[1] a market is "unconcentrated" if its HHI is less than 1,000, moderately

[1] See: Williams and Rosen, A better Approach to Market Power Analysis, Tellus Institute, July 14, 1999, P. 3

concentrated if the HHI is between 1,000 and 1,800, and "highly concentrated" if the HHI is above 1,800.

Q. What would the HHI be for each of the three islands if the estimates prepared by HECO were to occur?

A. In order to measure HHI, it is necessary to know the market share of each participant; HECO's analysis provides only their estimate for the market share that the utility would control. In computing the HHI, I have calculated a range, with the minimum HHI resulting from <u>each</u> non-HECO system having a <u>separate</u> vendor, and the maximum HHI resulting from <u>all</u> non-HECO systems having a <u>single</u> vendor. It does not really matter -- the share of the market that HECO expects to secure creates a highly concentrated market regardless of whether one or multiple vendors share the "crumbs" that are left over.

The HHIs for each of the three islands are shown below, and are calculated in COM-R-201. These are derived from the estimates prepared by HECO in Exhibit A of the CHP docket:

Hawaii CHP Herfindahl-Hirschman Indices If HECO CHP Estimates Achieved

Any Level Over **1800** is "Highly Concentrated"

System	Minimum HHI[2]	Maximum HHI[3]
HECO	5536	6174
HELCO	5491	6144
MECO	5917	6433

Q. What conclusions do you draw from this analysis?

A. Clearly approval of the HECO proposal for utility ownership of CHP systems would lead to a highly concentrated marketplace that would deter competition, potentially obstruct innovation, and delay market development. Mr. Kobayashi addresses in greater detail why this market concentration is undesirable in the distributed generation market in Hawaii.

Q. Have other Commissions considered the market power issue as it relates to utility ownership of distributed generation resources?

A. Yes. Mr. Kobayashi discusses dockets in Hawaii, New Mexico, and Louisiana in which the state Commissions have ruled that it is inappropriate for utilities to diversify into business areas that are not really "utility" service.

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[2] The "Minimum HHI" assumes that the utility owns the number of systems identified in Exhibit A, and each remaining system is owned by a separate vendor.

[3] The "Maximum HHI" assumes that the utility owns the number of systems identified in Exhibit A, and all of the remaining systems are owned by a single competing vendor.

In New Mexico, the specific rulings in 1996 was really very similar to the situation postulated in this docket: the utility was informed that it could not offer "optional" non-traditional services either as a utility or as a non-utility subsidiary, due to market power and audit issues.[4] I have discussed these cases with the then-presiding Chairman of the New Mexico Commission (Mr. Wayne Shirley, one of my colleagues at the Regulatory Assistance Project), and he has confirmed to me that market power concerns were a key element in these decisions.

Lost Revenue

Q. What is the lost revenue issue raised by the CA and by HECO?

A. Both of these parties express concern that non-utility DG will result in lost utility revenues. They somehow jump to the conclusion that this would result in higher rates to non-DG customers.

Q. Do you agree with their analysis?

A. No, there is no analysis to support their testimony, only unexplained allegation. There are two issues. First, will customer-owned and third-party DG result in lost utility revenues. Unquestionably, yes. Second, will this result in higher rates to non-DG customers. Almost certainly not – in fact, the opposite is the likely outcome.

Q. Please begin with measuring the lost revenue issues associated with customer-owned DG systems.

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[4] See New Mexico Public Utility Commission Cases 2655 and 2688.

A. Compared with utility service, the utility would lose the retail revenues paid by a customer. It would gain the standby revenues paid by the customer. The net of these two could be summed to measure the lost revenue. There is little doubt that this would be substantial. The example below suggests the magnitude of this for a customer with 500 kw of load that could be served with DG:

MECO Retail Lost Margin from 500 kw Customer

Element	Unit Cost	500 kw @ 50% Load Factor
Retail Rate	$.1558/kwh	$341,202
Variable Cost (estimated)[5]	$.11/kwh	($240,900)
Contribution to Fixed Costs	$.0458/kwh = $16.71/month/kw	$100,302

Q. Why would this not lead to higher rates for other customers?

A. Very simply because this calculation does not tell the whole story. A utility has <u>both revenues and expenses</u>. To measure only the lost revenues, but not the long-run avoided costs, is to look at the issue very deceptively.

First, the utility will avoid the need to invest in new generation, transmission, and distribution facilities. These avoided costs should be netted out from the "lost margin" calculation.

[5] I have not used the MECO variable cost from the 1997 rate proceeding, because fuel costs and electric prices have greatly increased since that time. The assumption of $.11/kWh in avoided variable costs is $.10 in fuel ($1.40/gallon / 10,000 BTU heat rate) plus $.01/kWh in variable lube oil and other generation maintenance expenses. This is consistent with the time period when MECO posted the average rate for Schedule P of $.1558/kWh.

Second, the utility will likely collect standby revenues from the DG customer (if the standby service is offered at reasonable rates), and these should also be netted out from this calculation. The only situation in which non-DG customers would pay more is if the utility cannot avoid more cost than it loses in revenue. In order to estimate this, we must have both an estimate of the avoided fixed costs, and an estimate of the standby revenues.

Q. How does the utility estimate it's avoidable costs?

A. The utility prepares marginal cost of service studies that show the avoided generation, transmission, and distribution costs. These are filed with the Commission in general rate proceedings. MECO's most recent marginal cost study was prepared in Docket 97-0346, and I discussed this in my direct testimony. The relevant marginal costs, for the purpose of this discussion, are as follows:

MECO Avoided Marginal Cost vs. Lost Margin

Cost	$/kw/month	$/year @ 500 kw
Production	$17.60	$105,600
Transmission	$2.70	$16,200
Distribution	$4.79	$28,740
Total Avoided Capacity Costs	$25.09	$150,540
Net **<u>Benefit</u>** to Utility of CHP customer leaving system	$8.37	$50,238

As is evident, the avoided capacity costs from <u>not</u> serving the customer ($150,540) greatly exceed the incremental contribution to fixed costs that the customer would pay if they were served ($100,302). Therefore, we would conclude from this simple analysis of marginal costs versus rates that other customers would pay higher rates if the customer IS served at tariff rates than if they left the system, and lower rates if the customer installs a CHP system. The reason for this is quite simple – MECO's marginal costs exceed it's average costs, and therefore any new load (or retained load of an existing customer) adds more to costs than to revenues.

Q. Did HECO make any estimate of the impact of this in preparing the CHP application?

A. Yes, Exhibit H in the CHP docket contains some calculations, but it does not develop enough CHP to result in multi-year or permanent deferrals of the Waena plant, and it appears that the cost levels used for avoided marginal costs are significantly lower than those now estimated. Both of these assumptions lead to what I believe are faulty conclusions. The issue is quite simple: the marginal cost of new generation greatly exceeds current rate levels, and new generation will result in rate increases. If new generation can be avoided by encouraging customer-owned CHP, rates for non-participant customers will be lower because the higher marginal costs of new resources will be avoided.

Q. This example you have calculated in your Exhibit COM-R-202 and summarized above is based upon MECO's last marginal cost study, prepared in 1997. What would be the result of substituting the much higher costs of capacity submitted by MECO in this proceeding for those used in the 1997 study?

A. The marginal generation capacity costs would be about 35% higher, and the net benefit of the customer leaving the system would be correspondingly higher.

Q. What about the recovery of fixed costs in the form of standby service charges. Would this also help to offset the lost margins due to customer distributed generation?

A. Yes, it would. As detailed below, standby rates should be designed to recover the full cost of providing standby service, taking into account the fact that customer diversity among standby loads means that one unit of standby generating capacity can serve more than one customer's standby demand. If conservatively designed, standby rates can be attractive to the customer, and more than compensatory to the utility.

Q. Have you included standby revenues in your calculation above?

A. No, I have not. Under the standby rate design I have proposed, the utility would receive an additional $1,000 to $2,000 in standby charges per month from this hypothetical customer, further increasing the system benefit of the customer self-generating. Alternatively, one could look at the standby revenue as offsetting any incremental transmission and distribution cost associated with providing standby service, as discussed below in the design of standby rates.

Marginal vs. Embedded Costs and Standby Rates

Q. What are the key issues in this docket relating to the development of standby rates?

A. The key issues are: first, to set rates that are fair to both the Company and to DG owners, so that the Company is fairly compensated for service, and second, to ensure that DG owners do not pay "full-time" for capacity that they need only sporadically and can share with other customers.

Q. How have the parties responded to this need?

A. HECO has provided little guidance. In most of its testimony, HECO recognizes that marginal costs can be avoided, and describes the benefits of doing so. On the other hand, Ms. Seese's testimony measures all types of 'equity" against embedded costs, but provides no guidance at all about the "efficiency" of the Company's current or future rates measured against marginal costs.

Q. In its testimony, the CA advocates that if rates were "unbundled" then the issues surrounding CHP would disappear. Do you agree?

A. No, and for two very different reasons.

First and foremost, MECO's current rates are based on embedded (historical) costs, while the costs it can avoid in the future are marginal (incremental) costs. On a growing system like

MECO's, only marginal costs are relevant when looking forward and trying to avoid future costs through encouragement of DG.

Second, there are "good ways" and "bad ways" to unbundle rates, and it is not at all clear what form of unbundling the CA is advocating.

Q. Please begin by discussing the marginal cost issue. Why is it inappropriate to set an unbundled rate design considering only embedded costs, as advocated by the CA and HECO?

A. As I discussed in my direct testimony, the average cost of MECO's existing generating plants is only $687/kw, while the incremental cost of new generating capacity is $3,000/kw. [Page 65, COM T-2] To unbundle the current rates, that are based on $687/kw of investment in production plant, would not send a meaningful price signal to a customer about the costs that would be incurred by MECO were that customer to increase load, or avoided by MECO if that customer were to decrease load. Only marginal costs provide that information.

Q. What has the position of HECO been on these issues?

A. HECO has been inconsistent. In the Ishikawa testimony T-4, at page 18, HECO correctly states:

> "...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 the Sakuda testimony, T-3, at page 5, HECO correctly states:

> "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."

These are examples of correct statements of marginal cost measurement, and the applicability of that measurement to the issues in this docket. DG can avoid the need for new generating capacity, and it is the cost of NEW capacity that is relevant.

Q. What is the conflicting evidence submitted by HECO?

A. In the Seese testimony, T-5, and in response to COM information requests, HECO has asserted that embedded (historical) costs are what is relevant:

> "Any loss of embedded fixed cost-rlated revenues due to customer self generation, regardless of whether such lost fixed cost-related revenues are lower or higher than marginal costs, will be shifted to other ratepayers."[6]

The appears to reflect a fundamental misunderstanding on the part of this HECO witness of what drives utility rate increases. If HECO can avoid the need for new power plants through DG (or DSM), it will avoid the need to raise rates. If it cannot avoid the need for new power plants, then the marginal costs of those new power plants will become the drivers for the next rate case – and <u>all</u> customers will face higher rates.

Q. Has Ms. Seese been consistent in her misunderstanding of the role of marginal costs?

A. No. In her testimony on uneconomic bypass, she states:

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[6] Response to COM-SIR-5

> "Uneconomic bypass occurs when the cost of a customer's alternative source of electrical energy is lower than the cost of receiving service under HELCO's applicable standard rate schedule, but higher than HELCO's **marginal** cost of providing service."

This is a correct statement. Since the utility's marginal costs exceed its average costs, avoiding load growth (or securing load reduction) is almost always an economic form of bypass, providing cost benefits to all customers. If the cost of new power plants were lower than the cost of existing units, this situation would be different, but as long as MECO is in a position to avoid a $3,000/kw power plant, and serve load with power plants costing less than a third of this amount, uneconomic bypass is not a real concern for MECO.

Q. Does DG create a risk of uneconomic bypass for the MECO system?

A. No, it does not. The MECO system is growing, with six new power plants scheduled for construction over the next decade. DG can defer or eliminate the need for some or all of these new power plants. Since these new units have marginal costs that greatly exceed system current average costs, deferring or avoiding them will prevent rate increases for existing customers. Therefore, it is reasonable to conclude that bypass is likely to be economic on the MECO system.

Q. Under what conditions would DG potentially lead to higher rates for existing customers?

A. The only circumstance under which the loss of utility load to DG would result in a shift of existing fixed costs onto remaining customers would be if MECO had a shrinking sales base and therefore DG development resulted in excess capacity. This is unlikely to occur, since each of the major systems (HECO, HELCO, and MECO) are growing, and the costs that can be avoided through DG exceed the embedded costs in rates. Further, in order for such a cost shift to occur, the Commission would need to find that the cost of the resulting excess capacity was appropriately borne by the remaining customers. There is no certainty that this would be the result of such a proceeding.

Q. Are there examples of proceedings in which regulatory commission have disallowed the cost of new generating facilities when utility loads migrated off the system, through economic or uneconomic bypass?

A. Yes. During the mid-1980's, many Commissions dealt with excess capacity situations caused by utilities building new power plants in advance of load, and simultaneously suffering load losses due to the combination of a weak economy and rising electricity prices. I was involved in several such cases. In Montana, the Commission found the Colstrip #3 coal power plant investment not "used and useful" because the utility did not need the resources to meet its test year loads.[7] In a case I was involved in in Arizona, the Commission ruled that a portion of the investment in the Palo Verde nuclear plant #3 was not needed to service retail customers for several years after the plant entered service, and deferred adding the cost to rate base until it was deemed "used and useful."[8] I recall that the New Mexico Commission denied inclusion of a portion of Palo Verde in rate base, and that Public Service Company of New Mexico has treated that as an unregulated investment since that time. I do not have a copy of the New Mexico Commission's order.

There have also been cases in the natural gas industry where the availability of "transportation" service (the gas-equivalent of retail wheeling) left utilities with lost margin. In some cases, the utility's ability to recover that lost margin was deferred for several years, until after a general rate proceeding, so there was no "dollar-for-dollar" recovery of the losses.

[7] Montana Department of Public Service Regulation, Order No. 5051c

[8] Arizona Corporation Commission, Order No. 57649

Q. Is there evidence produced by HECO that there are not likely to be stranded costs on the MECO system if there is rapid development of DG?

A. Yes. I have included both the Company's estimate of potential CHP capacity, from Exhibit A, and the Company's estimate of future generation addition needs, from Exhibit H in the CHP proceeding in my exhibit. These clearly show that the addition of DG to the MECO system will defer the need for and cost of expensive new generating facilities. Since MECO can defer generation additions, there is no reason it should experience any stranded costs as a result of customer-installed self-generation.

Q. Please summarize your discussion of marginal costs and how they apply in this proceeding?

A. I agree with the HECO testimony of Sakuda and Ishikawa, that the relevant costs to consider in evaluating the desirability of DG are system marginal costs, including avoidable marginal generation, transmission, and distribution costs. I disagree with the testimony of Ms. Seese and Mr. Herz that any form of rate analysis based on embedded costs should be relied upon to produce efficient results. Looking only in the rear-view mirror is not the safest driving style. We need to look ahead to costs that can be avoided.

Standby Rate Design

Q. How does all of this bear on the appropriate design of standby rates to customers that install DG equipment?

A. Customer that install DG equipment are helping the utility to avoid marginal costs. To the extent that marginal costs exceed embedded costs, the issues of lost margin and adverse impacts on non-participating consumers are resolved in favor of encouraging DG. This is unambiguously the situation for MECO, where DG can help avoid $3,000/kw generating facilities, and embedded costs reflect only $687/kw for generating facilities.

This leaves the issue of design of standby rates that are compensatory to the utility, and fair to the customer. The testimony of HECO and the CA provides little guidance on how to do this. HECO's rate design testimony focuses on embedded costs, which are relevant but not controlling, while the CA testimony discusses unbundling, without defining what it means or how to do it.

Q. Have other states established standby rates that are fair and reasonable to both the utilities and to customers?

A. Yes. California and New York have both adopted fully unbundled rate designs, and in so doing, adopted very sensible and reasonable standby rates for DG customers. Conversely, it would be possible to develop a standby rate that was inappropriate and unfair, but still in the guise of "unbundling." In order for the term "unbundling" to be meaningful, it must be defined, be examined, and be reasonable.

Q. How do you define an "unbundled" rate as it would apply to standby service?

A. An unbundled rate for standby service would separate out the customer-specific costs of connecting a specific customer to the utility grid from the costs of joint production and transmission facilities that are used by multiple customers. The customer would pay a fixed annual fee for the connection to the system, what is called a 'capacity reservation' payment, and a variable amount for actual standby service depending on how much and how often they actually require standby service. In this manner, a customer that used standby service very little (and therefore did not cause the utility to invest in facilities to provide standby service) would pay much less than one who relied on the utility frequently. It would provide an incentive for customers to install reliable equipment, and to maintain that equipment, while ensuring that customer using standby service frequently fully compensate the utility for providing firm year-round service.

Q. What type of rate would be least appropriate for standby service?

A. A rate that bundled the full annual costs of standby service for hundreds of days per year into a fixed fee that applies regardless of the frequency of standby usage would be an inappropriate standby rate design. A customer that uses standby service frequently should pay a much higher cost than one who seldom requires service, simply because the latter customer can "share" standby facilities with many more customers, and should be allowed to share the cost of those facilities with the other customers that use the standby facilities.

Q. What, in your judgment, is the best way to set standby rates for DG customers?

A. The rates should be set so that each DG customer contributes a portion of the cost of owning and maintaining the capacity that collectively provides service to all DG customers in proportion to how much and how often the individual customers use that standby capacity. Because HECO estimates that there will be many DG customers (with or without HECO involvement, and because DG systems are not all expected to be out of service simultaneously, it is only necessary for the utility to have a fraction of the combined DG capacity installed on its system in reserve in order to meet the standby needs of these customers.

Q. How do you estimate the amount of standby capacity the utility requires in order to provide standby service to DG customers?

A. One does this the same way one estimates the capacity needed to serve firm customers. First, one looks at the combined individual loads of the individual customers on the system. Second, one looks at the probability, or "coincidence" that these loads will occur at the same time. Finally, one measures this coincidence of loads against the other loads on the system to determine if additional capacity is necessary. Simply stated, if CHP systems are expected to operate 85% of the time, then the utility needs to have only 15% of the CHP capacity available in order to provide standby service; for example, if 50 1-MW systems are installed and have an average availability of 85%, the utility would need only about 7.5 MW of standby capacity in order to provide standby service without putting any pressure on firm customers even if there were no coordination of maintenance schedules. Under these circumstances, each standby customer should be expected to pay about 15% of the cost of a standby generator.

With coordination of maintenance into lower-demand months, the required standby capacity would be even lower.

Q. Are there steps the utility and Commission can take to reduce the cost of providing adequate standby capacity?

Yes. DG systems require annual maintenance, which can be scheduled, and also have forced outages, which can occur at any time. In the case of DG, the need for standby capacity can be controlled a bit, by requiring (as a condition of standby service) that the customers coordinate their annual maintenance outages and other scheduled outages in conjunction with the utility. This can assure that systems will not be taken out of service during the peak periods of the year – historically mid-summer, and Christmas break on the MECO system. While there is still the risk of forced outages, this risk is very small (typically less than 5% for modern CHP systems), and the utility needs only to have about 5% of the capacity of CHP customers available during peak periods to provide standby service. If this is done, the generation standby rate needs only to recover about 5% of the cost of a standby generator from <u>each</u> DG customer.

Q. Do some DG systems have higher reliability than others?

A. Yes. There are several types of DG systems, and several manufacturers. Each may have slightly different annual maintenance requirements, and slightly different forced outage rates. This can range from microturbine and IC engine systems with 90%+ reliability down to wind turbines and solar systems which may have much higher reliability (99%+) but much lower availability factors (30% - 50%).

Q. How can standby rates be designed to recover a fair amount of revenue from each type of DG installation?

A. The New York Commission has developed a very sensible approach to standby pricing that makes each standby customer pay a fair amount for the capacity they use from the utility. There are three parts to the standby rate:

> **Capacity Reservation Charge:** A $/kw/year charge that covers the cost of being connected to the utility, including net transmission and distribution capacity costs, that are customer-specific. This can include ancillary services that the utility provides at all times, such as spinning reserves. This should reflect the expectation that DG systems will bring transmission and distribution system benefits. It should be higher for customers served at secondary voltage than those served at higher voltages.
>
> **As-Used Daily Standby Demand Charge:** A $/kw/day charge that covers the cost of the generating capacity that the customer actually uses. A customer using standby service 100 days per year pays five times as much under this approach as one using standby service only 20 days per yea. Each standby customer therefore bears the cost of standby capacity in proportion to how often they use it. This should be lower on days of the week and months of the year when demand is lower and the utility does not

need to reserve any otherwise-unneeded capacity to serve the diversified needs of standby customers.

Standby Energy Charge: A $/kWh charge that recovers the variable cost of the energy used by the standby customer. In New York, this is a real-time energy charge, based on power pool dispatch conditions. In Hawaii it would most logically be a time-of-use energy charge, adjusted monthly for fuel costs.

Q. Does this type of rate design address the concerns raised by the other parties in this proceeding?

A. Yes, I believe it does. This is an unbundled rate design, as recommend by Mr. Herz.[T-1, P. 66]. It assures that the utility is fully compensated for both the capacity and energy used by standby customers, as recommended by HECO [T-5, P. 17]. It provides a predictable and reasonable rate for standby service that can be applied on a non-discriminatory basis, as recommended by HESS [Gregg, P. 3]. It does not "zero out" the standby charge as recommended by HREA [Bollmeier, table on final page], but it would greatly reduce the standby charge for customers with reliable systems compared, for example, with the extremely high (and, I believe, punitive) HELCO standby charge.

Q. How would you recommend calculating each of the elements for this standby rate?

A. Initially, I would recommend that the Standby Reservation Charge be set at one-half of the transmission and distribution charges in tariff rates. This recognizes the position of all parties that DG can provide transmission and distribution system benefits to the system. I recommend that all remaining fixed costs be recovered in the as-used standby demand charge. Variable costs would be recovered in the standby energy charge.

Q. In the longer-run, how should standby T&D costs be estimated?

A. I believe it would be appropriate to require the utilities to prepare IRP studies on the transmission and distribution system expansion requirements with and without DG systems in place for each circuit where capacity upgrades are anticipated within ten years absent DG investment. For those circuits, the avoided T&D costs can be estimated from the cost savings due to investment deferral. The standby rate should be based on the normal tariff rate (i.e., what the customer would pay if it were a full-requirements customer), minus the avoided cost for the utility from the DG installation (i.e., what the utility would avoid by the customer NOT being a full-requirements customer).

I would expect this to produce costs higher than the 50% benchmark I have proposed in some cases, and lower in others.

Q. Until there is extensive experience with multiple DG systems taking standby service, how would you design the As-Used Standby Demand Charge?

A. I would first subtract the standby Reservation Charge from the demand-related costs derived from the utility's cost of service study, to produce a net amount to be recovered through this as-used standby demand charge. I would then divide this by 200 days per year to produce a daily as-used standby demand charge. This rate would apply Monday through Friday; on weekend, one-half of the resulting rate would apply.

This would recognize that there is a significant probability that the forced outages of standby units would not be evenly distributed throughout the year, that on some days the utility would serve one outage in the morning and another in the evening, and charge for both, and that the utility would statistically have to have slightly more capacity available than a simple calculation based on the forced outage rates of the units to provide a high probability of being able to serve all standby demands.

I would apply one-half of the normal standby rate for service provided on Saturday and Sunday. This would provide owners of DG equipment an incentive to perform routine short-duration maintenance (such as oil changes on internal combustion engines) on the weekend, when system demands are typically lower even during the peak season.

Q. Have you computed a sample standby rate using these principles for the MECO system?

A. Yes. This is developed in my exhibit COM-R-203, based on the last cost study MECO prepared, and the results shown below:

Standby Rate Derived From MECO Cost Study			
Standby Reservation Charge:		$/kw/year	$32.88
(50% of T&D cost)			
As-Used Daily M-F Standby Demand Charge		$/kw/day	$0.98
(100% of Remaining Fixed Costs / 200 Days/year)			
As-Used Sat-Sun Standby Demand Charge		$/kw/day	$0.49
Standby Energy Charge (Computed monthly based on current fuel and other variable energy costs)		$/kWh	Monthly Variable Energy Costs

Q. You have computed these based on the embedded cost analysis prepared by MECO in its last rate case. You have previously testified that marginal costs should be the basis of efficient rate design. Please explain why you have used embedded costs?

A. Marginal costs are the correct measure of efficiency, but not necessarily the best measure of equity. In determining whether DG is "good" or "bad" for existing customers, it is appropriate to compare marginal costs to the revenues that would be foregone if customers choose DG. Under current Hawaii ratemaking practices, however, if the customer chooses tariff service, they would pay rates based on embedded costs. I have computed these standby rates using the same principles, so that there would not be discrimination. This is an *equity* consideration, not an *efficiency* consideration. Under this approach, customers would be encouraged to choose DG if it is efficient for them to do so, and would pay non-discriminatory and equitable rates to the utility for service provided once that decision is made.

Q. If the Commission adopts your proposal for a generation impact fee, based on marginal generation costs, would your recommendation change?

A. If generation impact fees were assessed (on a probability-weighted basis) on standby customers, they would have paid the difference between marginal costs of standby service and embedded costs in a one-time fee, and would be entitled to embedded-cost based standby rates as I have calculated above. If generation impact fees were imposed, as I recommend, on utility sales customers, but <u>not</u> on DG customers, then it would be appropriate to compute the standby rates using marginal costs. The standby reservation charge and standby as-used demand charge would be somewhat higher reflecting the fact that MECO's marginal costs exceed its embedded costs. My Exhibit COM-403 shows the derivation of this, but I note that the marginal costs used are out-of-date from 1997, and should be updated to reflect the $3,000/kw cost of the newest proposed power plants.

Q. In your direct testimony, you also proposed a "best efforts" standby rate, in which the utility would not be obligated to provide standby service if doing so caused its reserve margin to drop to unacceptable levels. How would this approach work in the context of the rate design formula you have proposed above?

A. A customer taking best-efforts standby service is not creating <u>any</u> requirement for the utility to invest in any generation or transmission plant or equipment to provide standby service. Arguably, there is no basis for the as-utilized daily standby demand charge at all. However, it is a precept of regulation that any customer using system capacity, at any hour, should help pay for the cost of that capacity.[9] Therefore I recommend that at least a nominal as-utilized demand charge should apply to best-efforts standby service. I propose that one-third of the normal standby demand charge (both standby reservation charge and as-used daily standby demand charge) apply to best-efforts customers.

Q. What behavior would you expect this approach to evoke?

A. I would expect customers with non-critical loads to choose best-efforts service up to the level of those loads. This could be industrial customers with process energy requirements, or resort hotels that can interrupt service to their water features, laundry, and other non-critical loads. If the customer's DG unit failed during a time when the utility was not under stress, it would then place that load on the utility if the utility had sufficient capacity, and contribute financially to the cost of that capacity. If the utility was under stress at that particular hour or day, the load would go unserved until the utility's reserve margin recovered. Since the probability of the failure of the customer's DG system at the same time the utility system is under stress is quite low, this might be a reasonable gamble for some customers. To the extent they choose this option, it would provide a contribution to the utility's fixed costs without actually imposing any corresponding cost on the utility. The utility's other customers would be made better off by the receipt of this revenue.

[9] See, e.g., Garfield and Lovejoy, <u>Public Utility Economics</u>, 1964, P. 163, quoting Dr. Henry Herz, NARUC Cost Allocation Committee: *"All utility customers should contribute to capacity costs; The longer the period of time that a particular service pre-empts the use of capacity, the greater should be the amount of capacity costs allocated to that service; Service that can be restricted by the utility should be allocated less in demand cost as the degree of restriction increases."*

Time Of Use Rate Design

Q. What has the Company testified with respect to time-of-use rates?

A. Ms. Seese testified that the current load-factor blocks in the Company's Schedule J and P are de-facto time of use rates.

Q. Do you agree with this assessment?

A. No I do not. The current rate design provides an incentive for customers to maximize their individual load factors, that is, to use power steadily 24 hours per day, 365 days per year. A time-of-use rate would encourage customers to use power sparingly during the priority peak hours of the day. The HECO/MECO/HELCO rate designs do not do this.

Q. Provide an example of how the current rate designs encourage uneconomic behavior.

A. Assume a hypothetical customer that has as their primary electricity use a night-time activity, such as security lighting for an automobile dealership. The customer is using power about 12 hours per day, but very little during the priority-peak hours of the afternoon from 1 - 6 P.M. when the utility experiences it's peak demand. With 360 hours per month of usage, the customer would fully consume the first block, and nearly fully consume the second block. Looking at the utility's rate schedule, this hypothetical customer would see that incremental usage – another 100 to 300 hours of usage per month – would be <u>much</u> cheaper than the current level of usage. In the situation this customer is in, however, the only hours remaining when they could consume power would be daytime hours – right when the utility experiences its peak demand. Any increase above 400 kwh/kw for this customer would <u>increase</u> the utility's peak demand.

Q. Is there an alternative that would promote greater efficiency for these systems?

A. Yes. The utility's current load factor blocks could be converted to time-of-use blocks. Ideally, the rate would be designed to produce the same revenue as the current rate design, but with all generation capacity costs reflected primarily in the on-peak and shoulder-peak energy blocks.[10] The demand charge would recover only transmission and distribution capacity costs. I have not fully designed such a rate, but have set out an example of what the final product would look like.

The table below, developed in Exhibit COM-R-204, shows the type of change to the rates that is appropriate:

TOU Rates In Place Of Load Factor Blocks		
Current Rate Design		
Demand Charge:		$10/kw
First 200 kWh/kw		$0.12
Next 200 kWh/kw		$0.10
Over 400 kWh/kw		$0.08
Alternative TOU Design		
Demand Charge:		$5/kw
Priority Peak		$0.15
Shoulder Peak		$0.12
Off-Peak		$0.08

[10] It is a well-understood principle of ratemaking that all customers that use capacity should contribute something towards that capacity, so even the off-peak rate should include some contribution to generation capacity costs; this avoids pure "hitchhikers" that use resources paid for by others.

Q. Are there reasons why time-of-use rates were not appropriate in the past, but are appropriate today?

A. Yes. In the distant past, when fuel costs were much lower, the utility may not have had such time-differentiated costs. Today each of the utilities plans to use high-efficiency combined-cycle power plants to meet baseload needs, and peaking units with much higher fuel costs during priority peak periods. To fail to recognize this in rates results in the potential for wasted oil. At current prices (as this is being written) of $50+/barrel, this is inexcusable.

Second, in the past, the cost of time-of-use metering may have been prohibitive. Today, the incremental cost of a TOU meter for the size of customers on Schedule P is trivial compared to the cost savings that might be achieved. The Commission should direct the immediate development of TOU rates for Schedule P (where the incremental metering costs for the relatively few customers not already having TOU capability are trivial), and evaluation and possible phased development for Schedule J (so that existing meters, as they wear out or become obsolete are replaced with TOU-capable meters).

Finally, in the past the cost of energy management systems for office buildings, hotels, and other large customers were quite high. As a result, their ability to respond to TOU prices were more limited. Today, energy management systems are a standard feature of new buildings, and a cost-effective retrofit investment for many existing buildings. Providing TOU pricing reflecting the utility's time-variant costs will provide an incentive for customers to use their energy management systems to save money for themselves and for the utilities.

Q. Do you routinely recommend TOU rates?

A. No. Much of my work is done in the Pacific Northwest, where hydro capacity provides most of the peaking power. The TOU cost differentials can be much smaller, and the costeffectiveness of TOU metering can be lower. I have found that TOU pricing is NOT cost-effective for residential customers, and I am not recommending consideration of residential TOU pricing in Hawaii at this time. However, for large customers (such as those on Schedule P), I nearly always find that TOU metering and pricing is cost-effective.

Q. How does this concept relate to the issues in this proceeding, the encouragement of distributed generation?

A. It relates in two different ways. First, with time-of-use rate design, the utility will be encouraging customers to choose DG system when the savings from those systems is cost-effective. Under the current rate design, the utility may be providing inefficient signals to customers, causing uneconomic investment (or lack of investment).

Second, and perhaps more important, if the utility established time-of-use rates for Schedules J and P, it could then easily implement time-of-use standby rates. These would provide the strongest possible incentive for DG customers to make sure their equipment is operating during on-peak periods. With the current rate design, the customer would have an incentive to take their equipment down for a continuous period -- day and night -- for maintenance. With a TOU rate, the customer would have an incentive to do maintenance during night-time hours spread over a longer period of time, keeping the equipment operating during peak periods when the output is most valuable and does the most to ensure reliable service to other customers.

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Summary

Q. Please summarize your rebuttal evidence.

A. First, I have testified to the market power issues that surround the proposal by the Company and the CA to allow the utility to enter the DG marketplace. I have demonstrated that this would lead to a highly concentrated market, in which the benefits of competition could not be expected to materialize.

Second, I have demonstrated that the lost revenue issues raised by the Company and by the CA are smokescreens, inapplicable to the current situation that MECO is in, with avoidable new power plants that cost more than three times as much as existing power plants. Any avoided load defers the needs for this expensive new generation, and will result in lower rates for other customers.

Third, I have developed a specific methodology for the development of unbundled standby rates that meet the goals of both the Company and the CA. These include a standby capacity reservation charge equal to one-half of the fixed costs of transmission and distribution, plus an as-used standby capacity charge, imposed on a daily basis, for actual use of standby service. I have demonstrated that this will result in reasonable costs for standby customers, and more than fully compensate the utility for any incremental facilities that are needed to preserve reliable service in the face of increasing DG use and increasing demands for standby service. I have also demonstrated a way to use these same principles to offer best-efforts standby service that is also fair to customers and also more than fully compensates the utility for the cost of service.

Finally, I have demonstrated that the Company's current load-factor block rate design is inefficient, and encourages uneconomic behavior. I have proposed an alternative time-of-use rate design that would encourage efficiency, and serve as the basis for time-of-use standby rates that would encourage optimal management strategies by DG owners.

This completes my rebuttal evidence.

HHI Estimates

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HECO			
		%	
Total Systems	97		
HECO-Owned	72	74.23%	
Other Owned	25	25.77%	0.0103093
HECO contribution HHI		5,510	
If all others sold by 1 firm:		664	
If all others sold by 1 firm per system:		27	
Minimum HHI:			5,536
Maximum HHI			6,174
Conclusion:		**Highly Concentrated**	

HELCO			
		%	
Total Systems	92		
HECO-Owned	68	73.91%	
Other Owned	24	26.09%	0.0108696
HECO contribution HHI		5,463	
If all others sold by 1 firm:		681	
If all others sold by 1 firm per system:		28	
Minimum HHI:			5,491
Maximum HHI			6,144
Conclusion:		**Highly Concentrated**	

MECO			
		%	
Total Systems	99		
HECO-Owned	76	76.77%	
Other Owned	23	23.23%	0.010101
HECO contribution HHI		5,893	
If all others sold by 1 firm:		540	
If all others sold by 1 firm per system:		23	
Minimum HHI:			5,917
Maximum HHI			6,433
Conclusion:		**Highly Concentrated**	

Source of data: HECO Exhibit A to CHP Filing

EXHIBIT COM-R-201

Example of Lost Revenues and Costs

Revenues

500 kw @ 50% load factor =	2,190,000	kwh/year
Average Rate:	0.1558	MECO website
Annual Revenue:	$341,202	
Variable cost/kwh	$0.11	Assumed
Fixed Cost/kwh	$0.0458	Calculated
Fixed Cost Recovery / Year:	$100,302	Calculated
Fixed Cost Recovery/kw/year	$200.60	Calculated
Variable Cost Recover / Year	$240,900	

Standby Charges

Reservation fee = $/year/kw	$25.00
Daily M-F As-Used Demand Charge = Annual Fixed Cost / 200	$1.00
Sat-Sun As-Used Demand Charge @ 50% of M-F Price	$0.50
Variable Rate = Variable Cost = $1.40/gallon / 10,000 btu heat rate + $.01/kWh	$0.11

Assumptions:
50 days standby/year; 30 days M-F at Full Price; 20 S/Su at 50% of Full Price
90% load factor on standby days (assumes CHP runs baseload)
kwh/year

Standby Revenues:

Reservation fee:	$12,500
As-Used Demand Charge:	$20,060
Total Contribution to Fixed Costs:	$32,560
Assume 5 Standby Customers Sharing Standby Capacity	$162,802
Gained Net Margin For Utility:	**$62,500**
Assume 10 Standby Customers Sharing Standby Capacity	$325,604
Gained Net Margin for Utility	**$225,302**

Substitute Estimated Current Costs for Former Estimates of Capacity Cost
Derived from MECO Marginal Cost Study

	1997	Current Costs
Monthly Cost/kw	$18	$23
Annual cost/kw	$211	$282
Annual real carrying charge rate	0.0939	0.0939
Capital Cost / kw	$2,249	$3,000
Ratio:		133.38%

EXHIBIT COM-R-202

MECO Standby Rates from COS Study

System Costs Per COS in 97-0346

Embedded Costs	**Monthly**	**Annual**
Demand		
Production	$13.66	$163.92
Transmission	$3.01	$36.12
Distribution	$2.47	$29.64
Total Demand Costs	$19.14	$229.68
Energy Cents/kWh		
Priority Peak	n/a	
Shoulder Peak	n/a	
Off-Peak	n/a	
Total Energy Costs	5.57	5.57

Note: Fuel costs and energy costs have risen dramatically, and these do NOT represent a reasonable estimate of current energy costs; variable standby charges should reflect current variable costs.

Step 1: Set Standby Capacity Reservation Charge = 50% of T&D Cost

Total T&D:	$5.48	$65.76
50% of T&D:	$2.74	$32.88

Step 2: Set Standby As-Used Demand Charge Based on Residual Demand Costs

Total Demand Costs:	$229.68
Less Standby Reservation Charge:	-$32.88
Residual Demand Costs	$196.80
Divide by 200 days of standby service/year	200
As-Used Daily M-F Standby Demand Charge	$0.98

Standby Rate Derived From MECO Cost Study

Standby Reservation Charge:		$/kw/year	$32.88
(50% of T&D cost)			
As-Used Daily M-F Standby Demand Charge		$/kw/day	$0.98
(100% of Remaining Fixed Costs / 200 Days/year)			
As-Used Sat-Sun Standby Demand Charge		$/kw/day	$0.49
Standby Energy Charge (Computed monthly based on current fuel and other variable energy costs)		$/kWh	Monthly Variable Energy Costs

EXHIBIT COM-R-203

Marginal Cost Based Standby Charge	**Monthly**	**Annual**
Demand		
Production	$17.60	$211.20
Transmission	$2.70	$32.40
Distribution	$4.79	$57.48
Total Demand Costs	$25.09	$301.08
Energy Cents/kWh		
Priority Peak	5.43	
Shoulder Peak	5.29	
Off-Peak	4.93	
Total Energy Costs	5.16	5.16
Note: Fuel costs and energy costs have risen dramatically, and these do NOT represent a reasonable estimate of current energy costs; variable standby charges should reflect current variable costs.		
Step 1: Set Standby Capacity Reservation Charge = 50% of T&D Cost		
Total T&D:	$7.49	$89.88
50% of T&D:	$3.75	$44.94
Step 2: Set Standby As-Used Demand Charge Based on Residual Demand Costs		
Total Demand Costs:		$301.08
Less Standby Reservation Charge:		-$44.94
Residual Demand Costs		$256.14
Divide by 200 days of standby service/year		200
Monday-Friday Standby Demand Charge		$1.28

Standby Rate Derived From MECO Marginal Cost Study			
Standby Reservation Charge:		$/kw/year	$44.94
(50% of T&D cost)			
Monday-Friday Standby Demand Charge		$/kw/day	$1.28
(100% of Remaining Fixed Costs / 200 Days/year)			
Saturday-Sunday Standby Demand Charge		$/kw/day	$0.64
Standby Energy Charge (Computed monthly based on current fuel and other variable energy costs)		$/kWh	Monthly Variable Energy Costs

EXHIBIT COM-R-203

TOU Rates In Place Of Load Factor Blocks		
Current Rate Design		
Demand Charge:		$10/kw
First 200 kWh/kw		$0.12
Next 200 kWh/kw		$0.10
Over 400 kWh/kw		$0.08
Alternative TOU Design		
Demand Charge:		$5/kw
Priority Peak		$0.15
Shoulder Peak		$0.12
Off-Peak		$0.08

Elements:

1) Demand charge recovers only T&D costs
2) Generation capacity costs recovered primarily in on-peak and shoulder peak energy charges.
3) Off-peak energy charge includes some generation capacity costs (as it does under present rates).

Rates are illustrative; actual rate design would require system costs and system billing determinants.

DATED: Wailuku, Maui, Hawaii, October 22, 2004.

BRIAN T. MOTO
Corporation Counsel
Attorney for Intervenor
COUNTY OF MAUI

By Cindy Y. Young
CINDY Y. YOUNG
Deputy Corporation Counsel

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing document were duly served upon the following by electronic mail and by United States mail, postage prepaid, on October 22, 2004, addressed as follows:

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