10-22-04

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

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PUBLIC UTILITIES COMMISSION

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PUBLIC UTILITIES COMMISSION	)	DOCKET NO. 03-0371
	)	
Instituting a Proceeding to Investigate Distributed Generation in Hawaii	)	
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REBUTTAL TESTIMONY (HREA-RT-1) OF WARREN S. BOLLMEIER II

ON BEHALF OF THE HAWAII RENEWABLE ENERGY ALLIANCE

RE:

THE IMPLEMENTATION OF A COMPETITIVE MARKET

FOR

DISTRIBUTED GENERATION IN HAWAII

AND

CERTIFICATE OF SERVICE

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SECTION I -- INTRODUCTION

Q PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A Warren S. Bollmeier II. I am an independent consultant, dBa WSB-Hawaii, in the fields of renewable energy, energy policy, integrated resource planning and public utility regulation. My office is located at 46-040 Konane Place, #3816, Kaneohe, HI.

Q PLEASE DESCRIBE YOUR EXPERIENCE AND EDUCATIONAL BACKGROUND

A I have worked since 1977 in research and development of renewable technologies on the mainland and in Hawaii since 1990, including development of windfarm projects, energy policy, and public utility integrated resource planning and regulation. I have degrees in engineering from the University of Texas and the Air Force Institute of Technology, and an MBA from Georgia State University. More details are given in **Exhibit No. HREA-RT-1-A.**

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS DOCKET?

A I am appearing on behalf of the Hawaii Renewable Energy Alliance (HREA).

Q WHAT IS THE SUBJECT OF THIS TESTIMONY?

A The subject of this testimony is a preferred market structure for distributed generation (DG) in Hawaii.

Q WHAT IS THE PURPOSES OF THIS TESTIMONY?

A The purposes of this testimony are to: (1) discuss further the efficacy of the framework to implement a structured competitive market for DG in Hawaii previously proposed by myself in my Direct Testimony (HREA-T-1), as submitted on this docket, and (2) address certain issues raised by the Companies (HECO, HELCO and MECO) regarding the benefits of the utility's direct involvement in the DG market.

Q PLEASE SUMMARIZE THE MAIN POINTS OF YOUR DISCUSSION ON THE EFFICACY OF THE PROPOSED FRAMEWORK TO IMPLEMENT A STRUCTURED COMPETITIVE MARKET FOR DG IN HAWAII AND CERTAIN ISSUES RAISED BY THE COMPANIES REGARDING THE BENEFITS OF THE UTILITY'S DIRECT INVOLVEMENT IN THE DG MARKET

A The main points of are:

- There are precedents in other jurisdictions for precluding the direct involvement of public utilities in DG markets (Louisiana and Pennsylvania) and an example where Public Utility Commission (New Mexico) encouraged a public utility, as an alternative, to provide certain "utility-related, non-utility" services via an unregulated, utility affiliate. This latter precedent specifically comports with HREA's proposed structured competition model;
- These precedents, in combination with HREA's previous arguments that the public utility's direct involvement in the DG market tilts the playing field heavily in their favor, suggest a compelling role for third parties as "non-utility" entities (or perhaps "private utilities") that provide specific energy services to a limited group of consumers;
- In addition to determining the appropriate role for the public utility, the correct price signals must be sent to the market. Therefore, I am proposing to remove current customer-class cross-subsidies and reveal the true energy fuel costs to customers, who can then make more informed energy choices; and

- A conservative estimate from an industry perspective is presented which compares the potential ratepayer impacts of utility-owned and operated Combined Heat and Power (CHP) with third party-owned and operated CHP. This analysis raises questions about the Companies' claim that utility-owned and operated CHP will provide more benefits to ratepayers than CHP that is paid for by others.

Q **HOW IS THIS TESTIMONY ORGANIZED?**

A **Section II** presents a refinement to the definition of distributed generation in Hawaii. **Section III** presents and discusses precedents regarding utility involvement in DG. **Section IV** presents a discussion of the potential ratepayer impacts from utility-owned and operated CHP versus third party-owned and operated CHP.

SECTION II -- DEFINITIONS

Q **PLEASE PRESENT YOUR REFINEMENT TO THE TERM DISTRIBUTED GENERATION IN HAWAII AND OTHER NEW DEFINITIONS.**

A The following is the term Distributed Generation as defined in my Direct Testimony (HREA-T-1):

Distributed generation (DG) includes supply- and/or demand-side devices and measures that provide electricity, thermal and/or mechanical energy. These resources can be located on-site or nearby to users. They can be used to meet baseload power, peaking power, backup power, remote power, power quality, and cooling, heating and power needs. DG includes energy supply devices ("prime movers") for providing electricity, thermal, and/or mechanical energy to users from on-site or nearby locations, and energy storage and interconnection equipment needed to interconnect with customers and/or the utility grid. Examples of DG are wind turbines, biomass cogeneration, hydroelectric plants, photovoltaics, fuel cells, microturbines, reciprocating engines, and pumped hydro storage. DG also includes demand-side devices and measures that include energy conservation and energy-efficiency.

The following is a refinement of the term Distributed Generation as defined above to clarify the importance of the type, size and location of the DG, and whether the DG is a utility or non-utility service or facility.

Distributed Generation (DG) in Hawaii. The following is a refinement (enhancement) of the DG definition as applied in Hawaii:

- DG is distributed (dispersed) in location from the central generation and therefore closer to load centers, and provides certain distributed benefits which need to be encouraged;

- For now, the size and type of DG should track that as defined in IEEE 1547, which currently covers interconnection of various types of DG (windfarm, CHP, PV, etc.) up to 10 MW;
- What is also important is whether the DG is supporting local site load, exporting wholesale power to the grid or both. This distinction can be sharpened by looking at whether the DG services one or a limited amount of customers vs. the system as a whole. The former could be considered a utility-related non-utility service, the latter, export of power to a public utility by a Qualified Facility (QF). Some specific DG examples and whether they constitute a utility-related non-utility service (URNUS), public utility and/or QF application include:
    - A CHP serving a hotel load only (URNUS),
    - A CHP serving a hotel load and exporting power to grid (URNUS in combination with a QF to export power to the grid),
    - A substation DG delivering power to the grid (URNUS or public utility),
    - A windfarm delivering wholesale power as a QF to the grid (QF), and
    - A windfarm for on-site power and/or export of wholesale power via to the grid (URNUS QF to export power to the grid).

<u>Non-Utility Services</u>[1]. Utility-related services are services that are provided by non-utility entities, such as Energy Service Companies (ESCOs) and DG providers, which may or may not be affiliated with electric or gas utilities.

<u>Utility-Related Services</u>[1]. Utility-related services are certain services (or products), such as provision of capacity, energy, and ancillary services to customers which: i) are not considered a necessity from a customer perspective even though they require use of certain utility assets; and, (ii) at times, may be delivered by non-utility entities.

Q **WHY ARE ALL THESE DISTINCTIONS IMPORTANT?**

A The question now before us is whether the utility should be allowed to provide certain utility-related services on either an above-the-line or below-the-line basis. HREA's position is that DG are utility-related non-utility services (or products). As such they should be performed by ESCOs, DG providers and/or utility affiliates. I will say more about this when I talk about precedents in other jurisdictions.

[1] See Exhibit HREA-RT-1-B: New Mexico Supreme Court Decision for a discussion of the terms non-utility and utility-related services.

SECTION III – PRESENTATION AND DISCUSSION OF PRECEDENTS REGARDING UTILITY INVOLVEMENT IN DG

Q **HOW MANY RELEVANT PRECEDENTS FROM OTHER JURISDICTIONS HAVE YOU FOUND AND FROM SPECIFICALLY WHAT STATES?**

A I have found three precedents relevant to public utilities from other jurisdictions, one each from the states of New Mexico, Louisiana and Pennsylvania.

Q **PLEASE DESCRIBE AND DISCUSS THE PRECEDENT FROM NEW MEXICO**

A In March 1998 the New Mexico Supreme Court upheld a New Mexico PUC decision to deny a request from Public Service Company of New Mexico (PNM) to provide new optional services to customers. Specifically, the PUC stated that the optional services consisted of "utility-related non-utility services." As such, the PUC 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 **WHY IS THIS PRECEDENT IMPORTANT?**

A While the requested services were not DG, the case set two important precedents. First, referencing page 5 of Exhibit HREA-RT-1-B, the term "utility-related non-utility service" was defined and used as a criteria for denying PNM's request. Specifically: "The optional services that PNMES '(PNM Energy Services)' seeks approval to provide are related to its core business of providing electric utility services, but are all discretionary from its customers' perspective. This means that the customer has a choice associated with the product or service. The choice reflects two facts: (i) the service is not considered a necessity even though it uses the assets of the utility; and, (ii) at times, that service or product may be delivered by others."[2]

Second, referencing page 5 of Exhibit HREA-RT-1-B, "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."

In summary, this case sets an important precedent for determining when a public utility: (i) should not be directly involved in a utility-related service, and, (ii) consider pursuing such service via an unregulated utility entity (affiliate). This approach comports with HREA's proposed structured competition model for the Hawaii DG market.

Q **PLEASE DESCRIBE AND DISCUSS THE PRECEDENT FROM LOUISIANA.**

A In May 1999, per Exhibit HREA-RT-1-C, the Public Service Commission (PSC) of Louisiana approved a proposal for a co-generation facility for on-site power consumption and sale of excess power to the grid 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 that sells electricity to third parties. PPG consumes power on site and the residual is sold wholesale by Entergy (as a QF)

[2] Recommended Decision of the Hearing Examiner for Case 2688 before the New Mexico PUC (1996).

to Entergy Power Marketing Corporation (EPMC), a wholesale power marketer affiliated with Entergy Corporation, a public utility in Louisiana, Arkansas, Mississippi and Texas. Note: Entergy would not be providing retail electric service to the public.

Q WHY IS THIS PRECEDENT IMPORTANT?

A While this is an example of a large cogeneration project, it mirrors essentially a smaller CHP installation, such as we could have in Hawaii, where a portion of the power is consumed on site and the residual sold wholesale (as a QF) to a public utility. Interestingly, this is a case where a public utility formed an unregulated subsidiary to participate in ownership of the cogeneration project. This follows the precedent recommended by the New Mexico PUC in the above case. However, rather than seeking approval on a case-by-case basis, HREA supports structuring a competitive the DG market where the public utility is allowed to participate in the DG market, if at all, only by forming an unregulated utility affiliate to compete openly in the DG market, conditional upon appropriate restrictions and requirements placed on the utility and its affiliate by the PUC.

Q PLEASE DESCRIBE AND DISCUSS THE PRECEDENT FROM PENNSYLVANIA

A In September 1998, per Exhibit HREA-RT-1-D, the Pennsylvania (PA) PUC reviewed a request from PEI Power Corporation (PEI Power) to provide electricity and steam to industrial and commercial tenants and property owners in an industrial park. The Commission determined that the proposed project would not constitute a public utility service, but rather would fall within the "defined, limited and privileged group exemption." Under PA law, a "private utility" is one that serves a "defined, limited and privileged group," exempting the private utility from regulation by the Commission. A public utility opposed PEI Power's request, arguing that PEI would become a public utility by completing the proposed project, in part by not being able to control and restrict the members of the class of people who could demand service. PEI Power subsequently proposed to place restrictive covenants on the landowners to address the utility's argument. The PUC found this approach acceptable and determined that PEI Power would not be a public utility by virtue of completing the project.

Q **WHY IS THIS PRECEDENT IMPORTANT?**

A This case is similar to the Louisiana, except that all power would be consumed on the industrial park site. This is similar to one large CHP that serves a single or limited number of customers on a site here in Hawaii. HREA observes that the private utility definition in PA comports well with the NM definition of "utility-related non-utility services." Specifically, HREA proposes that DG providers be designated private utilities, which provide utility-related non-utility services.

Q **PLEASE DISCUSS THE CURRENT PRICE SIGNALS TO THE MARKET AND DESCRIBE WHY IT IS IMPORTANT TO GET THE PRICE SIGNALS RIGHT,**

A Currently, there are cross-subsidies which skew the rates to the various customer classes. For example, on Oahu Schedule R (residential), Schedule H (commercial cooking, heating, air conditioning and refrigeration) and Schedule F (Public street lighting, highway lighting and park/playground floodlighting) customers are subsidized by Schedule G (non-demand), Schedule J (general, demand) and Schedule P (Large power) customers. See HECO Exhibit 501. The result is that the "residential et al." (Schedules R, H and F) customers do not pay the true cost for the service that the utility provides them, and vice versa, the "commercial et al." customers (Schedules G, J and P) pay more than the true cost for their service. Because the price signals are not correct, there are several consequences including:

1. residential et al. customers are granted a discount, which appears on the surface to be a good thing. However, there is less incentive to conserve electricity or to use it more efficiently. This, in turn, increases the amount of fossil fuel required to meet customer demand;
2. commercial et al. customers spend more for their electrical service, reducing the amount of funds available for other business expenses and activities. The higher rates can encourage energy conservation and efficiency, which on the surface appears to be good. However, this may result in uneconomic CHP applications; and
3. the proposed HECO CHP tariff would, in effect, provide a discount on electrical service to commercial customers, that would, in part, off-set the cross-subsidy to the residential customers. This would appear to be a band-aid applied on top of a band-aid.

Q **WHAT DO YOU RECOMMEND TO GET THE CURRENT PRICE SIGNALS RIGHT?**

A Basically, I believe there are three things we need to do, all of which may be simple in concept, but could prove to be difficult to implement.

Eliminate the cross-subsidies. First, we must correct the cross-subsidy situation. This will be tough, as residential et al. rates will go up, while commercial et al. rates will go down. However, on the good side, there will be additional incentive for residential et al. customers to conserve electricity and to use electricity more efficiently. This will help reduce overall electrical demand and save fossil fuel. For commercial et al. customers (especially schedule J), the initial consequence for some may be to stay with utility service as the lowest cost option, and use the cash savings for other business expenses.

However, I believe there will still be cost-effective DG applications, including CHP, for commercial customers. And, in the interest of our state energy policy, perhaps the utility should evaluate expansion of their DSM programs to encourage certain DG applications.

<u>Redesign the basic rates structure to so that charges are consistently applied</u>. The current system allows cross-category cost recovery. For example, the utility recovers a portion of demand costs in the energy charge. The rates must reflect actual costs, i.e., only demand costs are included in the demand charge, only energy costs in the energy charge, etc, and the resultant rates should be indicated on the customers' monthly bills. Specifically, one approach would be to include: (i) only billing services and an appropriate amount of administrative and overhead costs in the "customer charge," (ii) only demand costs (infrastructure costs for generation, transmission and distribution, fixed operations and maintenance (O&M) costs, and an appropriate amount of administrative and overhead costs in the "demand charge," and (iii) only energy costs (variable O&M) and fuel costs in the "energy charge." Finally, since the fuel costs are a "pass through" to customers, the fuel costs should be shown on customers' bills as a separate line item, e.g., non-fuel energy costs and fuel energy costs. Given these rate design changes and reporting on customers' bills, customers will be in a better position to make informed decisions about their energy needs.

<u>Replace the current block rate system with tiered-rates and/or time-of-use rates</u>. As a further refinement to the base rates structure, a tiered-rate and/or time-of-use rate structure should be implemented to further encourage conservation and energy efficiency. This would replace the current system which provides discounts for higher energy use. Once again, this is not the price signal that the utility should be giving the market.

Q PLEASE EXPLAIN THE PURPOSE FOR YOUR ECONOMIC ANALYSIS OF POTENTIAL RATEPAYER IMPACTS.

A The Companies have indicated that the CHP tariff has been designed to not unduly burden the ratepayers, and also claimed that there are net positive benefits to the ratepayers. In support of these arguments, the Companies prepared and presented a rather detailed and lengthy economic analysis of the costs and benefits of their proposed CHP tariff.[3]

The purpose of my analysis was to prepare and present a conservative estimate from an industry perspective of potential ratepayer impacts in order to determine if the Companies' claims held merit.

Q PLEASE DESCRIBE THE OVERALL APPROACH THAT YOU USED ON YOUR ECONOMIC ANALYSIS OF POTENTIAL RATEPAYER IMPACTS.

A A brief, two-page spreadsheet analysis was prepared to compare, from an industry perspective, the potential ratepayer impacts of utility-owned and operated Combine Heat and Power (CHP) with third party-owned and operated CHP. Due in part to time and resource constraints, the analysis was conducted for "Oahu only" in today's dollars. The key issues to be examined included the: (i) impacts of rate-basing utility CHP investments and the utility's CHP program and operating and maintenance (O&M) costs, including fuel costs, and (ii) potential revenue losses due to third party CHP facilities. Several important assumptions were made in the analysis based on data from HECO and DBEDT including:

1. A market of 44.3 MW as estimated by HECO in the year 2022;
2. A current system 1,300 peak load on Oahu growing to 1,600 MW in 2022 (estimated from HECO IRP);

[3] The Companies' Application for Approval of a CHP Program, Schedule CHP-Customer-Sited Utility-Owned Cogeneration Service, Inclusion of a Related Fuel Costs in the Energy Cost Adjustment Clause, and a Modification of the Energy Cost Adjustment Clause and Schedule Q, filed on October 3, 2003, reference Docket No. 03-0366.

3. An average utility rate (2001, DBEDT) of 11.36 cents/kWh, less 3.311 cents/kWh (fuel costs as of 9/04), which equals 8.05 cents/kWh,
4. HECO revenues (2001) of $882.3M;
5. HECO sales (2001) of 7,277 million-kWhs;
6. Use of diesel as the fuel of choice for this analysis; and
7. Annual Variable O&M costs of 1.5 cents/kWh (industry) and 1.8 cents/kWh (HECO).

In addition, several important assumptions were made in the analysis based, in part, on data provided by industry including:

1. Average Capacity factor for CHP units of 75%, which I believe is more realistic than the Companies' estimate of 85%;
2. An average system installation cost of $2,000/kW, which I believe is more realistic than the Companies' estimates which varied in their filing, but were less than $2,000/kW;
3. For purposes of this analysis, the annual costs of loans for utility investments were based on interest rates from 5% to 8% and estimated using a standard mortgage calculator;
4. An average heat rate of 9,300 Btu/kWh;
5. Energy content in a gallon of diesel fuel ranging from 128,000 Btu to 140,000 Btu, due to varying amounts of water in the fuel; and
6. The estimated price of diesel fuel to HECO includes a range from $1.00/gal to $1.25/gal.

Finally, the economic analysis was considered for the following two utility load growth cases: (i) load growth rate is positive, and (ii) no load growth.

Q PLEASE DISCUSS THE RESULTS OF YOUR ECONOMIC ANALYSIS OF POTENTIAL RATEPAYER IMPACTS.

A I would like to present the results in terms of the basic energy impacts of the anticipated CHP market, then discuss the costs and ratepayer impacts for the utility CHP, and finally discuss the costs and ratepayer impacts for the third party CHP. These results are indicated in Exhibit HREA-RT-1-E (Exhibit E).

Basic Energy Impacts. Please note that year 2001 data (utility rates, HECO revenues and sales) from DBEDT were used as a reference point, as these data are the most current available. The following are the key basic energy results:

1. The anticipated 44.3 MW of CHP would be 2.8% of the anticipated system peak load in 2022 (Line 8 - Exhibit E);
2. The average CHP capacity would be 33.2 MW (Line 9 – Exhibit E), resulting in an annual electricity output 291,242 MWH (Line 10 – Exhibit E);
3. The value of this electricity, given that it would be consumed primarily by Schedule J consumers, is estimated at $15.8 M to $18.8 M (Lines 12 and 13 – Exhibit E). Note: The effective rates for Schedule J customers (8.76 to 9.78 cents/kWh were estimated based on assumptions of a customer with a 500 kW peak load shown in Exhibit HREA-RT-1-F (Exhibit F);
4. The value of this electricity to HECO, as a percentage of their annual sales, ranges from 1.8% to 2.1% (Lines 14 and 15 – Exhibit E).

Potential Ratepayer Impacts from Utility CHP. Assuming that all of the 44.3 MW are installed, owned and operated by HECO, the required investment is estimated to be $88.6M (Line 18 - Exhibit E). The potential ratepayer impacts can be estimated from two categories – debt service requirements (with HECO profits, revenue/PUC taxes) and CHP program and operating costs. The following are the key cost results:

1. Annual loan payments (based on a 20-year term) range from $7.0M to $8.9M (Line 21-Left and Line 21-Right – Exhibit E);
2. With the utility profit (10%) ~~and~~ revenue/PUC taxes (9%), the total cost recovery required by HECO is estimated at $8.4M to $10.6M (Line 23-Left and Line 23-Right – Exhibit E);
3. Given the basic fuel energy assumptions, the amount of fuel required ranges from 19.3 to 21.2 million gallons/year (Line 30-Right and Line 30-Left – Exhibit E);
4. Given the fuel cost assumptions, the annual fuel costs range from $19.3M to $26.4M (Lines 31a and 31b – Exhibit E);
5. The annual variable O&M costs are $5.2M (Line 32 – Exhibit E);
6. The total operating costs, which are heavily influenced by the fuel costs, range from $24.6M to $31.7M (Lines 33a and 33b – Exhibit E);
7. The annual program costs of $250K is a HECO estimate of costs for labor, overheads, administration, marketing, see p. 9 of Docket No. 03-3066). With these cost (Line 34 – Exhibit E), the total Program and Annual Operating Costs range from $24.8M to $31.9M (Lines 36 and 37 – Exhibit E).; and
8. Finally, the total Required Annual Cost Recovery Requirements range from $33.2M to $42.5M (Lines 36a and 36b – Exhibit E).

Note: these impacts will build up over the period from now to 2022, reaching the totals noted above as all 44.3 MW of CHP are up and operating at the same time, which will would conceivably occur in the year 2022.

In any case, I believe this is a good reference case from which to compare with the case that all 44.3 MW of CHP were installed, owned and operated by the public utility versus third parties.

In summary, the potential ratepayer impacts are as follows:

1. Case 1 (positive load growth): installation of utility CHP will hopefully serve to defer new generation requirements However, it is not clear from this analysis or from HECO's CHP filing exactly who will pay for the total CHP costs. There are two clues, however, as to whether there will actually be net positive benefits to the ratepayers on Oahu.
   a. From Exhibit H of HECO's CHP filing, the estimated net positive benefit by 2022 is $2.262M (about $113K/yr). However, note that the annual benefits are negative in 11 of the first 12 years of HECO's proposed program. With the $250K annual program cost element, which not included in HECO's analysis, the annual average benefits would then be a NEGATIVE $137K.
   b. As noted in lines 37a and 37b of Exhibit E, the apparent rate requirement of HECO's CHP ranges from 11.4 to 14.6 cents/kWh. Of course, the capital costs would include both electrical and thermal equipment. So, for the purpose of this discussion, let's remove the debt service component. This results in an apparent rate requirement of 8.5 to 11 cents/kWh. Thus, it is hard to understand how HECO plans to recover their CHP program costs, including a 1 cent/kWh discount to CHP customers, without seeking recovery from non-Schedule J customers.
2. Case 2 (no load growth): installation of utility CHP will result in the addition of capacity before it is needed, and the annual cost recovery requirements for the utility investments ($8.4M to $10.6M) would then be an additional cost to be born by the ratepayers. If the output of the CHP is assumed to off-set output from HECO's central generation (CG), there may not be any significant impact from the projected operating costs of the CHP. However, there will be at least a $250K/yr impact from the programmatic cost element.

Potential Ratepayer Impacts from third party CHP. Primary impacts will vary depending on whether there is positive system load growth (Case 1) versus no system load growth (Case 2).

1. Case 1 (positive load growth). In this case, I take the view that view that it is more important to talk in terms of revenue opportunities as opposed to revenue losses. Specifically, third party CHPs would not be off-setting existing utility revenues. In effect, there is an opportunity for public utility (if-approved), third parties and utility affiliates (if they are formed) to compete for revenue opportunities in the positive load growth case. Therefore, I believe there are strong arguments for net positive benefits for third party CHP in this case:
    a. CHP investments are made by the third parties, and not subject to rate-basing, as would be the case with the public utility;
    b. There would be no revenue losses to the public utility; hence, no potential impacts to the rate base.
    c. Furthermore, the third parties would assume all risks associated with fuel costs; hence, no fuel costs have to be born by the ratepayers.
    d. In summary, all of the estimated public utility costs ($33.2 to $42.5M) – lines 36a and 36b in Exhibit E would be avoided.
2. Case 2 (no load growth). In this case, if third parties installed, owned and operated the 44.3 MW CHP there would be a potential revenue loss, which I have estimated at $15.8M to $18.8M/yr if all 44.3 MW of CHP were by third parties. On the other hand, for public utility CHP ratepayers would have to bear cost recovery required by the utility ($8.4M to $10.6M) for the same 44.3 MW, plus some elements of their program and operating costs. Finally, this analysis leaves out the impact of customers leaving the system, but if rate designs are corrected, as I have recommended, there will be no additional impact.

Q Q **DO YOU HAVE ANY FINAL COMMENTS?**

A I believe there are compelling arguments for establishing a competitive DG market in Hawaii, as previously proposed by HREA, i.e., the structured competition model. The role of the public utility would be to facilitate the evolution of the market, and, could elect to participate directly through an unregulated affiliate. These arguments include the following:

1. precedents in other jurisdictions that preclude public utility provision of utility-related non-utility services as defined and discussed herein;
2. the difficulty, if not the impossibility, of structuring a competitive market with a level playing field, if the public utility were allowed to participate directly; and
3. strong evidence that it will NOT be in the ratepayer's financial interests to allow direct public utility participation in the DG market (especially CHP). In the two cases examined (positive load growth and no load growth), there would be significant ratepayer impacts in the positive load growth if public utility CHP is allowed, and, subject to further review, similar impacts for both public utility and third party CHP in the no growth case. Given the current positive load growth scenario on the HECO system, this scenario is more likely, certainly in the near term. Also, if the rate designs are corrected, the rates for the potential CHP users will go down, further reducing the potential revenue losses.

Q **DOES THIS CONCLUDE YOUR TESTIMONY?**

A Yes

EXHIBIT HREA-RT-1-A

RESUME
WARREN S. BOLLMEIER II

PROFESSIONAL SUMMARY

Mr. Bollmeier has over 33 years of experience ~~in~~ solving technical, management and personnel problems. He has 27 years of experience in supervising, managing and conducting renewable energy projects and activities for government and private clients. He has extensive, detailed knowledge of and expertise in wind, solar and hybrid system technologies. He also has a working knowledge of biomass, geothermal, hydro, hydrogen, ocean and wave resources and energy conversion technologies. He has managed government-sponsored research, development and demonstration (RD&D) projects with a variety of industry, utility and other collaborative partners. He has developed and maintained a detailed knowledge of the design and deployment of renewable energy systems for remote power, village power and utility commercial applications. He has extensive, detailed knowledge and experience in developing and promoting energy policy issues at utility, state and federal levels, including integrated resource planning and regulated utility regulation.

Mr. Bollmeier has the abilities to provide clear definition of problems and to form and work with teams to implement sound projects and activities. He has excellent communication skills and has worked with a variety of U.S. and foreign government agencies, laboratories, universities, private organizations, industry, utilities and environmental advocacy groups. He has managed numerous projects both in the U.S. and overseas.

PROFESSIONAL EXPERIENCE

Wind Project Development (1996 to present). Mr. Bollmeier is a consultant to developers of new commercial windfarms in Hawaii. His clients include Zond-Pacific, Wailuku, HI and its successors, and Hawi Renewable Development, Chico, CA. The total expected capacity additions are 30 to 50 MW. This work has included preparation of an environmental impact statement for a windfarm that would be installed on State of Hawaii land on Maui.

Energy Policy Issues (1993 to present). Mr. Bollmeier is an advisor to Hawaiian Electric Company and Maui Electric Company on their Integrated Resource Plans (IRPs). In 1994 to 1995, he participated on a docket at the Hawaii Public Utility Commission (HPUC) investigating the role of renewables in Hawaii's utility market. In 1995, he helped found the Hawaii Renewable Energy Alliance (HREA) to promote the increased use of renewables in Hawaii. As HREA's President, he is working closely with State Legislators, the utility, state agencies, industry members, environmental activist groups and others to secure a renewable future for Hawaii. Mr. Bollmeier has also led HREA's lobbying activities at the Hawaii State Legislature. Mr. Bollmeier led HREA's intervention on HPUC docket initiated in 1997 on the possible restructuring of Hawaii's electric utility market and is currently leading HREA's intervention in a HPUC docket to investigate the role of distributed generation in Hawaii's electric utility market.

Solar Policy Analysis Workshop, Honolulu, HI, 1997. Mr. Bollmeier organized, coordinated and led a workshop for USDOE/NREL and the State Energy Office on solar policy options for Hawaii. The successful workshop included discussion of the State of Hawaii's solar tax credits, green pricing programs, net energy metering and broad- based policy support initiatives.

Sustainable Home Energy Use Guide, County of Maui, 1996. Mr. Bollmeier prepared a consumer-oriented guide for Maui County residents. The guide includes energy-efficiency, solar-hot water collector, photovoltaic system and small wind turbine options for homeowners.

Solar-Kiln Dryer Project, Pacific Center for High Technology Research (PICHTR), 1992 to 1994. Mr. Bollmeier managed a $250K joint project with Sumitomo Engineering Company, Tokyo, Japan. The project included a test evaluation of an innovative solar system that was used to dry wood and fruit products at a test site on the Island of Hawaii.

Wind/Pumped-Hydro Integration and Test (WPHIT), Pacific Center for High Technology Research (PICHTR), 1992 to 1994. Mr. Bollmeier managed a $550K project on the Island of Hawaii (Kahua Ranch) to demonstrate the integration of wind with pumped-hydro storage for utility application. The project included participation from the State of Hawaii Department of Business, Economic Development and Tourism (DBEDT)-Energy Division, the Hawaii Natural Energy Institute, Kahua Ranch Limited, and the Hawaii Electric Light Company.

Downhole Coaxial Heat Exchanger (DCHE) Demonstration, 1990 to 1993. Mr. Bollmeier managed a $560K, U.S.-Japan project to demonstrate the DCHE concept. The U.S. partners included PICHTR and DBEDT. The Japanese partners included the Ministry of International Trade and Industry (MITI) and Sumitomo Engineering Company. An experimental test evaluation was performed at the HGP-A geothermal site on the Island of Hawaii.

Cooperative Field Test Program, SERI, 1984 to 1989. Mr. Bollmeier managed 13 cooperative research agreements for USDOE with wind industry partners. The projects included testing of utility scale wind turbines and siting studies ($2.3M total value).

Wind Energy Conversion Systems (WECS) Technology Group, Small Wind System Program, 1982-1984. Mr. Bollmeier managed a small group of engineers and technicians that were responsible for field testing of commercial wind turbines in California.

Wind Energy Assessment, USDOE/Government of Yugoslavia, 1984. Mr. Bollmeier was a member of a USDOE team that assessed wind energy potential in Yugoslavia.

Wind Turbine Demonstration Project, USAID, Cape Bon, Tunisia, 1983 to 1984. Mr. Bollmeier managed a demonstration project for USAID in conjunction with the Solar Projects Office, NASA, Plumbrook, Ohio. He coordinated with the Tunis Mission Office and the Tunisian Electricity and Gas Company (STEG). The project included resource and site assessment, design, procurement, pre-commissioning tests, packaging, shipment and installation of two 10 kW wind turbines at Cape Bon, Tunisia.

Hybrid-Energy System Project, 1982 to 1983. Mr. Bollmeier managed a hybrid energy system project for the U.S. Army, Ft. Huachuca, AZ. The project included design and testing of a complete system consisting of three small wind turbines (total of 5 kW), two photovoltaic systems (total of 3 kW), a battery and control system.

System Development Group Manager, Small Wind Systems Program, 1980 to 1982. Mr. Bollmeier managed the System Development Group (three engineers and one administrative assistant) and directed 14 separate projects for new wind turbine designs ($15M total value). The project included design, fabrication, and testing of prototype units at Rocky Flats, CO.

Technical Monitor, Small Wind Systems Program, 1997 to 1980. Mr. Bollmeier managed three subcontracts ($1.7M total value) for the development of small (1 to 2 kW), high-reliability, wind turbines for remote applications. Two of these contractors subsequently commercialized wind turbines for remote and village power applications.

Project Engineer, Solid Rocket Division, Air Force Rocket Propulsion Laboratory, Edwards AFB, CA, 1974 to 1977. As an USAF Captain, Mr. Bollmeier was responsible for two RD&D projects ($3.1M total value) to develop solid rocket motors for upper stage launch vehicles. He also provided technical support to the Space Defense Vehicle and Space Shuttle Programs.

Systems Engineer, Engineering Division, Air Force Plant Representative Office, Lockheed-Georgia Company, Marietta, Georgia, 1971 to 1974. As an USAF lieutenant, Mr. Bollmeier approved production design changes to the C-5A landing gear, ground-support and personnel subsystems, and monitored Lockheed's system safety and human engineering programs.

EDUCATION

B.S., Aerospace Engineering, University of Texas-Austin, Austin, TX, 1969
M.S., Aeronautical-Mech. Engineering, Air Force Institute of Technology, Dayton, OH, 1971
M.B.A., Management, Georgia State University, Atlanta, GA, 1973

PROFESSIONAL ORGANIZATIONS

America Society of Mechanical Engineers

American Solar Energy Society
American Wind Energy Association
Geothermal Resources Council
Hawaii Renewable Energy Alliance
Hawaii Solar Energy Association

TECHNICALREPORTS/PUBLICATIONS

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EXHIBIT HREA-RT-1-B

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

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

I.

{2} In Commission Case 2655, PNM Gas Services[4] 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[5] 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 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.

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

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

{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.[6]

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); 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.

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[6] 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.

{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

WE CONCUR:

GENE E. FRANCHINI, Chief Justice

PAMELA B. MINZNER, Justice

PATRICIO M. SERNA, Justice

DAN A. McKINNON, III, Justice

EXHIBIT - AREA-RT-1 - C

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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.
(originally published by PMA OnLine Magazine: 05/99)

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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

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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.

BACK TO TOP

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.

EXHIBIT - HNEA - RT - 1 - C

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.

EXHIBIT - HREA-RT-1-C

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BACK TO TOP

EXHIBIT- HNEA-RT-1-D

PMA ONLINE MAGAZINE

COVER PAGE
POWER REPORT
PMA HOME
JOBS SITE
AD INFO
ARCHIVES SEARCH

STATELINE by Robert Olson

October 1998

PENNSYLVANIA: PUC DECLARES COGENERATION FACILITY SERVING LIMITED CLASS, NOT A PUBLIC SERVICE UTILITY

by Robert Olson -- Brown, Olson and Wilson, P.C.
(originally published by PMA OnLine Magazine: 10/98)

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On September 3, 1998, the Pennsylvania Public Utility Commission declared that a proposed utility service by PEI Power Corporation ("PEI Power") which would provide electricity and steam to industrial and commercial tenants and property owners in its industrial park does not constitute a public utility service regulated by the Commission, but rather falls within the "defined, limited and privileged group" exemption. The Commission's decision was premised upon the placement of restrictive covenants, binding upon successors, in contracts with the consumers who were landowners.

A Pennsylvania statute defines a public utility as those " . . . producing, generating, transmitting, distributing, or furnishing . . . electricity, or steam . . . to or for the public." 66 Pa. C.S. §102. The "to or for the public" element has been discussed by Pennsylvania's courts. Under Pennsylvania law, a private utility is one that serves a "defined, limited and privileged group," exempting the utility from regulation by the Commission. The leading Pennsylvania case concerning this exemption permitted a landlord to provide gas, electricity, and water service to the

EXHIBIT - MREA - R7 - 1 - D

residents of its apartment complex and stores in the complex without regulation by the Commission. Each of the consumers was in a landlord-tenant relationship with the utility, thus allowing the utility to control and restrict who could demand service. The Pennsylvania decision set forth a test for determining whether a utility is public or private. The determination depended upon whether "anyone outside of the special class, which the service provider has the ability to control and restrict to a defined group, is privileged to demand service."

BACK TO TOP

A utility opposing PEI Power's petition for declaratory order argued that PEI Power is a public utility. The Utility argued that the inclusion of landowners in the class could result in unknown successor landowners and PEI Power would ultimately not be able to control and restrict the members of the class of people who could demand service. In supporting its argument, the Utility cited another Pennsylvania case in which a service provider sought to provide water to tenants and property owners in a condominium association. There, because the utility had only a service provider and customer relationship with the property owners at the condominium, and could not control successor owners, it could not control and restrict the ultimate members of the class. Under those facts, the water service provider for the condominium association was considered a public utility.

In response to the problem of control over successor landowners, PEI Power proposed to place restrictive covenants on the landowners. PEI Power explained that some of the potential occupants of the industrial park, for financing reasons, would choose to purchase land rather than leasing land, which prevented it from limiting the industrial park to tenants only. PEI Power stated that the special class which could demand power of PEI Power consisted of "large, sophisticated industrial and commercial" business tenants and landowners located within PEI Power's industrial park. In further support of its proposal, PEI Power pointed out that its plant and the industrial park will revitalize the region. The plant was closed last year by a prior owner, eliminating fifty jobs, and had been slated for demolition. Another benefit of PEI Power's proposal was that it intended to eventually move toward a 100% waste-source methane gas fired facility.

The Commission found that PEI Power's proposal to provide service to landowners, without restrictive covenants, placed it outside the exemption because PEI Power would not have sufficient control over the landowners. However, because PEI Power owns all the land in the industrial park, the Commission found it is able to place restrictive covenants in contracts with purchasers which would provide that any subsequent purchaser (a) is a substantial energy user, (b) would use the property in a

EXHIBIT - HAEA RT-1-D

manner consistent with the industrial park, and (c) would not cause PEI Power to become a public utility. The restrictive covenants are to prohibit the landowners from selling their property without approval from PEI Power. In light of the restrictive covenants, the Commission found PEI Power has the requisite control to restrict the special class which constitutes its customers to a "defined, limited and privileged group." The Commission added the fact that a class of persons served is of a defined geographic region, is of a certain number, or of a certain class (commercial and industrial as opposed to residential) does not determine whether a "defined, limited and privileged group" is served.

PEI Power also sought a declaration that it is not a regulated public utility under the "designed, constructed, and utilized exception" to Commission jurisdiction. This exception applies where a facility is "designed or constructed to serve a select type of business" and where the facility is "constructed or sized to serve a definite number of customers." The Commission found the facility did not fall under this exception. According to the Commission, while the facility would be for commercial and industrial businesses, this designation is not selective enough for the exception. Also, the facility will not be constructed and designed to service a definite number of customers; rather, PEI Power actually planned for expansion for any additional customers within the industrial park who would be interested in receiving their service.

Soon after the order was issued by the Commission, PEI Power announced a contract with an industrial user in the 275 acre park. A PEI Power spokesman said its power prices will run 25%-30% below the market. PEI Power has already been selling power into the Pennsylvania-New Jersey-Maryland Interconnection and steam to a greenhouse at the park.

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BACK TO TOP

Brief Economic Analysis of a 3rd Party versus Utility Ownership of CHP on Oahu
(from an Industry Perspective)

What are the Potential Revenue Losses from a 3rd Party Ownership?

Line	Assumptions	Value	Comments
1	CHP Penetration	44.3	MW (HECO estimate - Exhibit A of CHP Tariff filing)
2	Peak Load	1,600	MW (estimated HECO peak load during this period)
3	Avg. CHP Capacity Factor	0.75	Ratio (from vendor estimates of typical CHP installation)
4a	CHP Customer (Sched J) Utility Rate (low)	8.76	cents/kWh - Source: Exhibit HREA-RT-1-F
4b	CHP Customer (Sched J) Utility Rate (high)	9.78	cents/kWh - Source: Exhibit HREA-RT-1-F
5a	Adjusted Utility Rate (HECO)	5.45	Line 4a less 3.311cents/kWh (fuel costs) - See Note 1
5b	Adjusted Utility Rate (HECO)	6.47	Line 4b less 3.311cents/kWh (fuel costs) - See Note 1
6	Annual HECO Revenues	882,308,000	$ (in 2001) - Source: DBEDT (Oahu only)
7	Annual HECO sales	7,277	million-kWhs (in 2001) - Source: DBEDT (Oahu only)

Line	Calculations	Value	Comments
8	CHP/Peak Load	2.8%	Line 1 divided by Line 2
9	CHP Average MW	33.2	Line 1 times line 3
10	CHP Annual MWHs	291,242	Line 9 times 8760 hours per year
11	CHP Annual kWhs	291,241,530	Line 10 times 1,000
12	Value of Electricity/Potential Revenue Loss (low)	15,858,833	Line 5a times line 11 divided by 100
13	Value of Electricity/Potential Revenue Loss (high)	18,838,129	Line 5b times line 11 divided by 100
14	% of HECO Revenues (low)	1.8%	Line 12 divided by Line 6
15	% of HECO Revenues (high)	2.1%	Line 13 divided by Line 6

What are the Potential Ratepayer Impacts?

a. Debt Service Revenue Requirements

Line	Assumptions	Value	Comments			
16	CHP Penetration	44.3	MW	Same as Line 1		
17	Installed Costs	2,000	$/kW	From Vendor estimates		
18	Total Investment	88,658,000	$s	Line 16 times Line 17 times 1000		
19	Utility Loan Period	20	Years	HECO's preferred CHP contract term		
20	Utility Loan Rate (s)	5	per cent		8	percent

Line	Calculations - See Note 2	Value	Comments			
21	Annual Loan Payments	7,021,245	$s		8,898,852	$s
22	Utility Profit + Revenue/PUC Taxes	1.19	Multiplier = 1 + (10% utilty profit + 9% taxes)/100			
23	Total Debt Service Requirements	8,355,282	Line 21L X L22		10,589,634	Line 21R X L22

Note 1: per note 1 in the Exhibit to HECO's response to HESS DT SIR 1c.

Note 2: Using a standard mortgage calculator

b. Programmatic and Operating Costs

Line	Assumptions	Oahu	Comments			
24	Fuel Type	Diesel				
25	Estimated Fuel Costs to HECO	1.00	$/gal	to	1.25	$/gal
26	Average Heat Rate	9,300	Btu/kWh		From vendor estimates	
27	Diesel (energy/gallon) - Note 3	128,000	Btu/gallon	to	140,000	Btu/gallon
28	Annual Variable O&M (Industry/HECO)	1.5	cents/kWh	to	1.8	cents/kWh

Line	Calculations	Value	Comments			
29	Diesel (energy/gallon) - Note 4	13.76	kWh/gallon	to	15.05	kWh/gallon
30	Fuel Required (gallons/year)	21,160,517	Line 11/Line 29L	to	19,346,759	Line 11/Line 29R
31a	Annual HECO Fuel Costs (low)	19,346,759	Line 30R times Line 25-Left			
31b	Annual HECO Fuel Costs (high)	26,450,647	Line 30L times Line 25-Right			
32	Annual HECO Variable O&M Costs	5,242,348	Line 11 multiplied by Line 28-Right, divided by 100			
33a	Total HECO Operating Costs (low)	24,589,106	Line 31a added to Line 32			
33b	Total HECO Operating Costs (high)	31,692,994	Line 31b added to Line 32			
34	Annual HECO Program Costs	250,000	From HECO Filing			
35a	Total HECO Program + Operating Costs (low)	24,839,106	Line 33a added to Line 34			
35b	Total HECO Program + Operating Costs (high)	31,942,994	Line 33b added to Line 34			

c. Total Potential Ratepayer Impacts

Line	Calculations	Value	Comments
36a	Total HECO Required Annual Cost Recovery (low)	33,194,388	Line 23L + Line 35a
36b	Total HECO Required Annual Cost Recovery (high)	42,532,628	Line 23R + Line 35b
37a	Apparent Rate Requirement - cents/kWh (low)	11.4	Line 36a divided by line 11 times 100
37b	Apparent Rate Requirement - cents/kWh (high)	14.6	Line 36b divided by Line 11 times 100
38a	Apparent Rate Reqt. - cents/kWh (low) - see note 5	8.5	Line 35a divided by line 11 times 100
38b	Apparent Rate Reqt. - cents/kWh (high) - see note 5	11.0	Line 35b divided by Line 11 times 100

Note 3: vendor estimates - the heat value in diesel fuel will vary depending on the percentage of water in the fuel

Note 4: line 27 (left and right) divided by line 26

Note 5: Apparent Rate Requirement without debt service recovery

EXHIBIT HREA-RT-1-F

Example of Typical Utility Rates on Oahu

Schedule J

Assumptions

1. Customer Charge (Three phase):	60	$/month
2. Demand Charge	5.75	$/month/kW
3. Energy Charge varies:		
Tier A. First 200 kWh/month/kW =	8.6900	cents/kWh
Tier B. Second 200 kWh/month/kW =	7.5419	cents/kWh
Tier C. Over 400 kWh/month/kW =	6.5130	cents/kWh

Calculations of Monthly Electric Bill for Schedule J

Peak (kW)	Avg Load	Mon kWh	Tier A kWh	Tier B kWh	Tier C kWh
500	0.5	182,500	100,000	82,500	-
		Energy Charge	8,690	6,222	-
Total Bill	17,847			Eff. cents/kWh	9.78
Peak (kW)	**Avg LF**	**Mon kWh**	**Tier A kWh**	**Tier B kWh**	**Tier C kWh**
500	0.75	273,750	100,000	100,000	73,750
		Energy Charge	8,690	7,542	4,803
Total Bill	23,970			Eff. cents/kWh	8.76

Party		Party	
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Dated: October 22, 2004

President, HREA