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Before the Hawaii Public Utilities Commission

Direct Testimony and Exhibits of Jim Lazar, Consulting Economist

On Behalf of County of Maui

FILED
JUL 15 1 57 PM '04
PUBLIC UTILITIES COMMISSION

Docket No. 03-0371

July, 2004

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INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, address, and occupation, and summarize your utility regulation experience.

A. Jim Lazar, 1063 Capitol Way S. #202, Olympia, Washington, 98501, USA. I am a consulting economist specializing in utility rate and resource issues. I have been engaged in utility rate consulting continuously since 1979. During that time, I have appeared before many local, state, and federal regulatory bodies, authored books, papers, and articles on utility ratemaking, and have been a faculty member on numerous occasions at training sessions for utility industry analysts. I have appeared before numerous regulatory commissions, including the state Commissions of Washington, Oregon, Idaho, Montana, Arizona, Illinois, Hawaii, and California. the British Columbia Utilities Commission and the Manitoba Public Utilities Board. I am also an Associate with the Regulatory Assistance Project (RAP), headquartered in Gardiner, Maine; my work with RAP involves advising regulatory bodies throughout the world on the implementation of effective utility oversight programs. In that capacity I have assisted with training programs in India, China, the Philippines, Brazil, Namibia, Mozambique, and Indonesia. A statement of my experience in contained in Exhibit COM-200.

Q. In what capacity have you appeared before the Hawaii Public Utilities Commission?

A. From 1991 through 1997, I was a consultant to the Hawaii Consumer Advocate. In that capacity I prepared expert testimony in proceedings involving HECO, MECO, HELCO, Kauai Electric, and Gasco. The latter two companies have been superseded by KIUC and TGC. I appeared before the Commission in many proceedings; some were resolved by settlement and stipulation.

I prepared expert testimony in 1993-94 in the Commission's Avoided Cost proceeding, Docket 7310. Many of the issues in that proceeding are directly on-point to issues in this proceeding. Nearly all issues in that docket were resolved by stipulation, and the remaining issues were briefed. The Commission has not yet entered a final order in that docket.

Q. Do you have other relevant experience in the public utility area in the state of Hawaii?

A. Yes. In 1990, I was retained by a non-profit organization, The Hawaii Energy Coalition to prepare and present a series of workshops on Integrated Resource Planning. These were attended by representatives of public interest groups and state agencies with an interest in the then-pending proposal to create an IRP rule in the state.

In 2002, I was a part of a consulting team retained by HECO to propose some alternative approaches to resource evaluation, resource acquisition, and rate design for their internal consideration.

In 2003, I was a part of a consulting team retained by the Research Corporation of the University of Hawaii to prepare a study of the utility regulatory framework in Hawaii. This report, entitled Hawaii Energy Utility Regulation And Taxation, was prepared as a part of the Hawaii Energy Policy Project. The lead author was Carl Freedman.

In addition, I have been a frequent holiday visitor to Hawaii since 1984, and am familiar with energy-related issues on each of the islands.

OVERVIEW

Q. Please provide an overview of your testimony.

A. My testimony discusses several important topics, in support of the policy testimony provided by Mr. Kobayashi.

First, I discuss the role of the regulated utility and the role of the regulatory commission. I am concerned that these roles may be confused when opportunities for non-utility supply of power become opportunities that are before the regulatory commission.

Second, I discuss benefits of distributed energy resources, and the reasons why these competitive alternatives should be provided by the competitive sector, not by regulated utilities.

Third, I discuss economic and uneconomic bypass, and point out that because MECO's costs of building new generating facilities are so much higher than existing power plant costs, there is a benefit to existing customers from having new load served by distributed generating facilities.

Fourth, I discuss a "virtual power plant" proposal, to knit together existing emergency and other on-site generating facilities to provide backup service to the entire MECO grid.

I discuss a number of ratemaking practices that would facilitate the development of distributed generation and other distributed generating resources. Key among these is establishment of generation impact fees to recover the high cost of new power plants from customers causing growth to the system, and requiring multi-year contracts from large customers to prevent risk to core market customers.

Finally, I address a number of specific actions that I believe the PUC should take in this docket, including resolving certain issues such as the involvement of the utility in distributed generation, and establishment of reasonable standby rates, and convening further dockets in areas such as rate design.

Q. To the extent that you discuss energy efficiency issues in your testimony, is that discussion within the context of the issues in this proceeding?

A. Yes. Order 20831 instituting this docket specified that this docket would focus on distributed generating resources. It noted, however, that all issues relating to distributed energy resources, including efficiency, were appropriate for discussion in this proceeding so long as they affected the same policy issues as relate to distributed generating resources. All of my discussion of efficiency is in this context – the establishment of progressive policies and ratemaking practices that encourage development of cost-effective distributed generating resources will also encourage development of cost-effective on-site renewable resources and energy efficiency resources.

THE ROLE OF A MONOPOLY PUBLIC UTILITY

Q. What is the role of a public utility, as you understand it?

A. This role has been well established in the economic literature, and incorporated into the public service laws of Hawaii and other states.

First and foremost, a public utility is to provide safe, efficient, and reliable service to all customers who request it and are reasonably entitled to service. This is the "obligation to serve."

Second, public utilities are obligated to charge rates that are "fair and reasonable" and "non-discriminatory" as determined by the regulatory commission. I will discuss this process below, when I discuss the role of regulation.

Third, public utilities should facilitate customer investment in cost-minimizing options to meet their energy needs. In some cases, the utility itself should make the investment, and in other cases, customers should make the investment.

Q. Why is this role different than that of unregulated enterprises?

A. A public utility is granted certain privileges that unregulated or less-regulated businesses do not receive. First, it is granted a (generally exclusive) franchise to operate utility distribution facilities throughout a service territory; MECO is the only electric utility with a franchise to serve Maui at the present time. Second, it is granted the power of eminent domain to acquire property needed to provide service (subject to PUC approval). Third, it is provided with rates that at times may be in excess of what a competitive industry might offer in the short-run in order to ensure that investments needed in the long-run will be available when and as needed.

In exchange for these privileges, the utility is obligated to provide service whenever requested, subject to reasonable rules and regulations, and to charge non-discriminatory prices to all customers.

Q. Please begin with the obligation to serve. In the context of Maui Electric, what does this involve?

A. First it means planning to meet the power supply needs of customers and constructing transmission and distribution facilities to deliver that service. MECO has generally met this test well. It is important for the regulator to put in place incentives and penalties that ensure that the utility will meet this obligation.

Second, it means having a set of rules and regulations that ensure that customers receive all of the service that they are "reasonably entitled to" demand. This may require that large customers execute multi-year contracts for service, since the utility must make significant investments to serve them, and losing such a customer on short notice could leave the utility with a stranded investment. This is less necessary for small customers, because a residence or small business that is vacated by one tenant is likely to be re-occupied by another, and in any event the amount of investment at risk is insignificant in the context of the total utility investment. This concept is important in Maui County, as I will explain below.

Third, it means having adequate reserve capacity and some redundant facilities available so that service is uninterrupted during "normal" equipment maintenance periods and malfunctions. This is a very different situation than is the case for most unregulated industries – in most businesses, if a major component breaks, the entire enterprise may shut down. For storable commodities, or those for which ready substitutes are available, this is not a significant problem for consumers; for something as crucial to modern living as electricity, it is deemed unacceptable by most regulators, and utilities are expected to be prepared for reasonably foreseeable contingencies. This becomes important as we discuss standby rates and distributed generation later in this testimony.

Q. Now please turn to the issue of encouraging customer investment in cost-minimizing options. Why is this a role of public utilities?

A. Experience has shown that a monopoly utility with a long time horizon will apply different investment criteria to long-lived assets than its customers might. For example, experience with commercial customers suggests that they insist on a 2 - 4 year payback period on some energy investments, compared with a 10 - 30 year life of the investments. Utilities will make investments based upon the life-cycle of their assets, because they have a reasonable expectation of being able to charge rates to captive customers that recover this investment, and are allowed front-loaded cost recovery to reduce the risk of holding such investments.

The realization that markets for energy are quite "imperfect" has led many regulatory bodies, including the Hawaii Public Utilities Commission to adopt "Integrated Resource Planning" processes. These ensure that utility-owned investments and alternative ways to meet energy requirements are evaluated on a common basis, and the utility is guided to the most cost-effective option, regardless of who "owns" the asset or whether it is a supply-side or demand-side resource.

This is crucial in this docket, because there are many distributed energy resources which are cost-effective in Hawaii today that may reduce the state's reliance on imported fuels, that may enhance the economic well-being of Hawaiians, and that may reduce the total cost of meeting energy end-use requirements in Hawaii. My testimony and that of Mr. Kobayashi discuss many of these options, and how progressive regulation needs to ensure that the best options are developed in a cooperative and timely fashion.

Some of these options are generating resources, including both renewable technologies like wind and solar energy, and conventional generating resources and CHP systems that may be distributed at customer locations around the utility service territory. Some of these opportunities are demand-side distributed energy resources, such as more efficient lighting, water heating, and air conditioning equipment.

Q. You have indicated that market failures led to the need for utility involvement in demand-side resources. Does the same hold true for distributed generating resources?

A. Yes, but to a different extent, requiring different responses. There is a well-developed global industry providing distributed generating resources (including combined heat and power systems, or CHP), and the typical customers to which these apply are large enough to make rational and economic decisions. Therefore there may not be a need for the utility to be involved in evaluating or financing such options.

However, making those decisions may depend on having utility pricing in place that provides the right incentives for customers to make the right choice. This includes connection terms and conditions that help to put on-site generation on a common playing field with utility-owned generation, and availability of standby service offerings that allow customers to obtain (and pay for) such reliability services as may be needed to make their choices economic to both the customer installing on-site generation without imposing an unreasonable burden on other utility consumers.

The market failures that afflict demand-side resources require utility involvement in the provision of least-cost services, while those that affect supply-side resources may only require that the utility rate design provide appropriate cost-based information in the rate design to allow potential users to make informed decisions, and provide information, education, and quality assurance programs to ensure that competitively-supplied equipment is reliable and compatible with the utility system. This level playing field should be established by aligning the cost and pricing information on alternatives at the time of new construction through appropriate utility connection policies, and by ensuring that desired utility ancillary services needed by customers are available on reasonable terms and conditions.

THE ROLE OF REGULATION

Q. In the context of this proceeding, what is the appropriate role of regulation?

A. The appropriate role of regulation is first and foremost, to provide a mechanism to encourage the utility to provide safe, adequate, and reliable service at the lowest cost possible consistent with service quality objectives. Second, to balance social goals, including environmental protection, land use and visual pollution concerns, dependence on imported fuels, and so forth with the first objective. Third, to protect monopoly customers from unfair prices or unfair service policies that would not occur if a competitive marketplace for utility services could exist. And finally, to provide the utility with a reasonable opportunity to earn a fair rate of return on its prudent investment, assuming efficient management practices.

Q. Of these objectives, which are more important to emphasize in this proceeding?

A. The second and third objectives, balancing social goals and protecting monopoly customers are relatively more important in this proceeding. The other goals are common to all rate-related proceedings before the PUC.

Q. What is the regulatory role of balancing social goals particularly important in this proceeding?

A. First, distributed energy resources have very different social and environmental impacts than do conventional utility resources.

Distributed fossil fuel generating resources (including CHP) may also have beneficial social characteristics. They may use a smaller amount of fuel, reducing the state's dependence on foreign oil. They may use a cleaner fuel, such as propane or naphtha, rather than diesel fuel. They may have more efficient fuel utilization, due to use of the waste heat in CHP installations as well as avoidance of transmission and distribution losses. They typically will have a larger local labor content than central station generation, leading to a stronger local economy.

Renewable resources such as wind generation and solar water heating have much lower pollution impacts than do conventional generating resources. Regulatory policies that facilitate distributed generating resources will also encourage renewable resources being developed. This would be consistent with many policy goals enunciated by the Hawaii legislature and governor.

Distributed resources, both renewable and conventional, also help to avoid the land use impacts of new central station generating facilities. MECO is planning a new generating facility site, and this will require both dedication of this land use (and associated air quality and visual impacts) and construction of necessary transmission facilities to integrate this development to the MECO distribution system. Distributed energy resources at customer premises could eliminate this need and the associated impacts.

As Mr. Kobayashi discusses, the benefits of distributed generation on Maui are considerable, and the regulatory role of considering these benefits should not be slighted. To the extent that these benefits accrue to the public, not to the utility, it is natural that the utility may be less than enthusiastic to these options.

Q. What about protecting monopoly customers? What specific issues does this proceeding raise in that arena?

A. There are at least three classes of "monopoly customers" affected by the decisions that the PUC makes in this proceeding. First, there are existing utility consumers, who will be adversely affected if decisions made in this proceeding cause their utility rates to be higher or their quality of utility service to be lower. Second, there are the existing customers who have an opportunity to install distributed energy resources, but whose on-site economics are affected by the availability of reasonable utility standby service to their on-site resources. Third, there are new utility customers whose options include full reliance on utility service or partial self-sufficiency, and whose decision will be affected by the policies the PUC adopts with respect to new customer connections.

Q. What is the interest of existing utility customers in the results of this proceeding?

A. Existing customers have an interested in minimizing their utility costs, and preserving their access to reliable service. This means that they will generally want to encourage development of distributed energy resources, while making sure that partial-requirements customers provide fair compensation to the utility system for use of utility resources.

As I discuss in greater detail later in this testimony, MECO's proposed new power plants have much higher costs than its existing resources – on the order of $3,000 per installed kilowatt (a figure provided by MECO and included in Exhibit COM-201, but one that seems almost unimaginably high), compared with less than one-fourth that amount for existing generating resources meeting their needs. If load growth on the MECO system forces the construction of an expensive new generating facility, rates will inevitably rise. These customers have a vested interest in preventing (or deferring) the need for this new development.

However, existing customers also have an interest in the reliability of their service. If MECO makes standby service available to those customers with distributed generation capabilities, this will place an additional burden on these resources, reducing their availability to meet existing customer needs. To prevent a reduction in overall reliability, MECO can augment its facilities to protect service reliability; the cost of doing so should form the basis for standby rates. Later in this testimony I propose that two different types of standby service be offered, at two different prices. The first would be "firm" standby service, in which MECO has the same obligation to partial-requirements customers as to other customers, and would be assessed a premium price. The second would be "best efforts" standby service, which would make service available if and only if it could be provided without impairing service reliability to other customers.

Q. What is the interest of potential users of distributed energy resources in the results of this proceeding?

A. These customers have an interest in being free to choose alternative resources, and to have the cost of those resources measured on an equitable basis with use of utility service. They also have an interest in being able to access utility service for supplementary service (when their own resources do not meet their total needs) and for standby and maintenance service (when their own resources are out of service), so that their total energy requirements are met. They want to pay a price for these services no greater than is necessary to provide "fair" compensation to the utility.

By "fair" in this context, I mean enough revenue that the cost of maintaining existing levels of reliability for other customers does not increase. I will discuss this in greater detail later in this testimony under the topic of "standby rates."

Q. What is the interest of new utility consumers in the results of this proceeding?

A. New consumers want the utility to provide the service they need, when they need it. They expect to pay "fair" rates for this service. It will remain for the PUC to determine what "fair" means with respect to new customers in a rising-cost environment. New customers also want to be able to choose between full reliance on the utility for service, partial reliance on the utility, and complete self-reliance.

Q. Is there any likelihood that a competitive supplier of standby service will develop in Maui?

A. On a system as small as MECO's, it is unlikely that a third-party supplier of reliability services could emerge, so MECO will remain a monopoly for these services.

Q. In your opinion, are these various interests compatible, and can the PUC render a decision in this proceeding that meets all of these interests?

A. I believe that they are compatible, but that it will mean some "give and take" for all of the possible positions in order to achieve an optimal outcome.

First, I think the Commission needs to adopt generation impact fees so that new customers see the costs of the energy resources they cause to be developed at the time of construction. These should be calculated in a manner similar to the current utility impact fees applied to distribution line extensions, providing for recovery at the time of service initiation of any costs of providing new service that are not reflected in rates. This is necessary to align the interests of new customers with those of existing customers. In the realm of land use regulation, these type of impact fees are common and are imposed on new customers for water, sewer, parks, fire protection, transportation, and other impacts on these public services. In the electric utility area, generation impact fees can be implemented very easily. However, I also recommend that connection "credits" be considered for customers that go above and beyond minimum efficiency codes in reducing the impact they impose on the existing utility system; these would be a part of the utility DSM programs.

Second, I think that the Commission needs to implement reasonable standby rates and charges. I discuss these in detail below, and will note here only that standby customers typically impose less of a reliability burden on the system than do full-requirements customers, and should only pay a portion of the fixed costs of service that are collected from full-requirements customers.

Third, I believe that the Commission should move rate design in the direction of having the marginal prices seen by customers more closely approximate the long-run costs of developing additional power supplies. In general, MECO's current declining block rates that apply to large customers should be replaced with time-of-use rates.

If these steps were taken, I expect the following beneficial outcomes:

- New large-property developers would often install combined heat and power systems to utilize waste heat associated with electricity production;
- MECO would avoid the need for new generation and transmission development, at least deferring the need for its new power plant.
- Rates and bills for existing customers will rise more slowly than under current policies;

- The total cost of providing energy services will be lower;
- System reliability will improve, due to the benefits of a more diverse power supply;
- Reliance on foreign oil will be reduced;
- Concentrated air emissions will be reduced;
- Large users will see lower energy bills, due to the benefits of on-site resources
- Developers would be more likely to install solar water heating in new homes;
- Commercial developers would choose more efficient lighting and air conditioning systems;

Q. What are the possible results of the Commission taking a less constructive approach to distributed energy resources?

A. If the Commission does not take steps to encourage the development of distributed energy resources, MECO will need to develop a new power plant sooner, and the economic and environmental benefits listed above will not materialize. Maui businesses will be competitively disadvantaged, and existing residential and general service customers will pay higher electricity bills.

WHY COMPETITIVE ALTERNATIVES SHOULD BE PROVIDED BY COMPETITORS, NOT BY THE ELECTRIC UTILITY

Q. Why should alternatives to central utility generation of electricity be provided by non-utility providers, rather than by the utility itself?

A. The principal reason is to prevent the utility from engaging in discriminating monopoly pricing. A discriminatory monopolist is an enterprise that offers customers with competitive alternatives competitive rates, and customers without competitive alternatives monopoly rates. The overriding goal of regulation is to provide the regulated monopoly with incentives to be as efficient as a competitive marketplace would be if the service being provided were of a nature that made competition viable.

As the author of one of the seminal texts on public utility regulation wrote:

> *"The essential purpose of such regulation is to achieve the results of competition in the form of (a) reasonable prices, or rates and reasonable profits; and (b) adequate service quality."*[1]

If the utility is allowed to provide discriminatory service at competitive prices to those customers with competitive options, and to supply power at monopoly prices to those that do not, it loses at least a part of the incentive to make its monopoly operations more efficient that the "fear" of competition for those customers with competitive options provides.

Q. Is this perspective well recognized in the field of public utility economics?

A. Yes. In the most comprehensive recent text on utility regulation, Dr. Phillips states:

> *"Assume that a regulated utility offers a basic service for which there are no close substitutes and another service for which there is a close substitute supplied by an unregulated firm. How can the commissions insure that the regulated enterprise does not use the power at its disposal in the "monopoly" area of its business to eliminate (via internal subsidies) competition in the "competitive"*

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[1] Garfield and Lovejoy, Public Utility Economics, 1964, p. 1:

area?[2]

Q. Please provide an example of how a utility might exercise monopoly power?

A. Suppose that the utility's average cost of providing service to a class of customers was fifteen cents per kilowatt-hour, but that one customer with a competitive alternative could meet its own needs with a CHP system for twelve cents. If the utility were allowed to provide the CHP system, it could serve the customer at twelve cents, and continue serving all other customers at fifteen cents. If the utility were allowed to charge excessive standby rates to customers choosing CHP from other vendors, it could keep them from entering the market. This would be an exercise of market power.

If it could "hide" a portion of the cost of providing the CHP systems in the books of the regulated utility, it might well be able to offer the CHP system at a cost of eleven cents, underbidding the competition, but still being profitable, and charge monopoly customers sixteen cents, subsidizing the competitive sector offering. Examples I have personally witnessed included assigning labor costs, real estate costs, office space and equipment costs, legal costs, administrative costs, insurance costs, employee benefit costs, and vehicle costs associated with competitive services to the monopoly utility functions. These type of internal subsidies are extremely difficult to track and police, and they force monopoly customers to subsidize competitive sector customers.

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2 Phillips, The Regulation of Public Utilities, 1985, p. 63

If, on the other hand, the utility were constrained to providing only non-discriminatory utility service, it would have an incentive to control its costs to get its overall cost of service down to twelve cents to retain the load of the customer with a competitive option. If it succeeded in doing so, **all** customers would benefit, not just the customer with the competitive alternative.

Q. Are there other reasons that alternative suppliers should be encouraged to enter the energy marketplace?

A. Yes. One reason is that competition is more likely to lead to technological innovation. This has clearly been the case in telecommunications, where opening the industry to competition has led to rapid evolution of sophisticated calling services, cellular technology, lower long-distance costs, and lower total communication bills for consumers.

There are multiple different vendors of CHP equipment worldwide, and inviting competition is a way to ensure that the best quality of equipment is available to customers. In it's CHP application, HECO indicated that it had selected a single vendor to provide CHP systems in Hawaii. In my opinion, this kind of narrow approach restricts competition and potentially denies the citizens and businesses in Hawaii the opportunity for competition and the savings it can evoke.

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.

Q. Should the regulated utility be allowed to engage in the CHP market through an unregulated, separately-capitalized subsidiary?

A. In general, no. Within the utility's service territory it is important to preserve the incentive for the utility to concentrate on its core mission -- providing reliable service to all customers at a fair and non-discriminatory cost. It may be acceptable to allow an affiliate to offer competitive services outside of its service territory.

I have had extensive experience reviewing affiliate transactions involving regulated utilities and their unregulated cousins. In my opinion, it is all-but-impossible to audit and verify that the affiliates are not benefitting from the relationship with the utility. If the Commission does approve any affiliate engaging in sales within the utility service territory, the affiliate should be required to pay appropriate royalties to the utility for the use of the company name and reputation. The marketing advantage associated with having a corporate relationship to the utility is considerable.

Q. Is there any role for the regulated utility in evaluating alternative resource providers equipment?

A. Yes. The utility will likely be called upon to provide standby and maintenance service. Customers will be interested in the reliability of the equipment they are considering, and the utility may be in a position to assemble information on which types of systems are likely to require the least in the way of utility backup. Assisting customers with the selection of equipment is little different than providing information on efficient appliances to residential customers – in order for "competition" to produce an "efficient" result, customers need access to "perfect" (or as close as is reasonably achievable) information.

If the utility is also marketing distributed energy resources, it may have a bias in providing objective information. By precluding the utility from entering this market while still providing information to consumers, the PUC will also be assisting customers in choosing the best possible resources.

By keeping the utility focused on providing it's own product as efficiently as possible, and facilitating customer understanding of available alternatives, the PUC will encourage the most efficient ultimate result. Customers will choose utility service when it is the best option, choose increased efficiency where it is more economic than increased utility reliance, and consider on-site generation, renewable resources, or CHP systems where they best meet the customer's needs.

Additionally, the utility can provide customer support in the form of information, education, and quality control. The utility currently does this with solar water heaters and other measures that reduce demand on the utility. Extending this to provide quality assurance for other distributed energy resources, including on-site generation, may be helpful to ensuring that customers obtain quality products that reliably meet their energy needs.

BENEFITS OF DISTRIBUTED ENERGY RESOURCES TO ALL CUSTOMERS

Q. What are the benefits of distributed energy resources?

A. Distributed energy resources benefit the public in many ways. First and foremost, there are reliability benefits, in the form of supply diversity and supply reliability. There are benefits of fuel diversity, reducing oil dependency. There are transmission and distribution system benefits if resources are located in or near load centers. Finally, there are local economic development benefits. All of these benefits can help strengthen the

Island economies if pursued properly.

Q. Please begin with supply diversity. How do distributed energy resources provide this benefit?

A. A distributed network of energy resources means a larger variety of resources providing energy supply, including efficiency measures, renewable resources, combined heat and power systems, and linking together existing emergency generators, all working together with the utility's central generating system and transmission network. By using multiple technologies, dependence on any one technology or resource is reduced.

Q. How does this lead to improved supply reliability?

A. Having a large number of small generating units leads to a more reliable network. This is one reason that MECO has a large number of small generating units to begin with. It would clearly be more economical to have a single modern 300 megawatt combined-cycle unit serving the total electric load in Maui, but the reliability risks would be unacceptable. By spreading the load to multiple generators, multiple locations, multiple technologies, and multiple fuels, the risk of any one unit failing and causing a widespread outage or shortfall is minimized.

Q. How can distributed energy resources improve fuel diversity?

A. MECO is currently very oil dependent. We have had past oil supply disruptions in the past, and severe price volatility in recent years. Distributed energy resources, including combined heat and power, renewable resources, and efficiency measures use a variety of fuels, not all of which are subject to the same market pressures as oil. First, renewable resources like solar and wind energy are fuel-free resources, so there is no market risk. Propane is a quite different market than diesel fuel, and while the prices will normally retain a relationship, the supply of propane in Alaska makes this a surplus fuel in the Western United States. Many CHP systems operate on propane, in part due to their proximity to tourist facilities and a desire to minimize odor and other environmental impacts of using oil. Efficiency measures are also immune to fuel price volatility and fuel supply risk.

Q. How do distributed resources provide transmission and distribution system benefits?

A. Quite simply, because they are located at load centers, most distributed energy resources reduce the need for transmission and distribution facilities. To the extent that customers desire firm standby service from the utility, the utility may still need to invest in adequate capacity to carry their local demand, but even in this situation, most of the time the transmission and distribution facilities will be lightly loaded, and the line losses are typically lower at lighter loading levels, so all customers will benefit from this investment when it is not needed to serve standby loads.

I recommend below that two types of standby service be offered, both firm and "best efforts" service. If best efforts service is selected by a customer with distributed generation on-site, the utility would not need to construct additional facilities, and the customer would not be entitled to service if the system were under stress. It is quite possible that a customer might choose firm standby for a portion of their load, and best-efforts standby service for the rest, so that they could provide security lighting and other essential needs at all times, but accept the risk of disruption of some of their activities. If this option is selected by customers, the utility will receive revenue to offset the distribution system costs, but have no corresponding distribution system investment. Non-participating ratepayers will benefit.

ECONOMIC AND UNECONOMIC BYPASS

Q. What is meant by the term "bypass" of a utility system.

A. Bypass occurs when a customer chooses some source of energy other than utility supply. Self-generation, cogeneration, and on-site renewable generation are typical forms of bypass. But one need not look that far for encouraging examples -- each time a customer installs a compact fluorescent lamp in place of a incandescent lamp, a form of "bypass" occurs. The customer is using a different option to meet their end-use energy needs.

Most bypass is very desirable. MECO is only about 35% efficient at converting oil at its generating stations to electricity at the customer's meter. For example, incandescent lamps are only about 12% efficient at converting electricity to lighting; the rest is emitted as heat. This means that only about 4% of the energy content of the oil does useful work for the customer.[3] CHP systems can be 85% efficient turning fuel into useful work. Certainly no regulatory policy would want to discourage a doubling or tenfold improvement in efficiency.

Other examples of bypass of the electric utility, besides energy efficiency, include:

- On-site renewable energy systems (including geothermal heat pumps)
- On-site combined heat and power systems
- Stand-alone self-generation.
- Fuel choice (using gas for water heating)
- Solar water heat

Q. What does the term "economic bypass" mean?

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[3] If the customer's lamp is in an air conditioned space, the thermodynamics are even worse – the customer must spend additional electricity removing the heat from the building, and the net efficiency of the lighting system can be as low as 2%.

A. Economic bypass occurs when the life-cycle incremental social cost incurred for the alternative energy supply are lower than the life-cycle incremental social cost that would be incurred by the utility to serve the energy demand.

Q. What do you mean when you use the term "social cost?"

Social cost means all economic costs and quantifiable environmental and social costs and benefits that are incurred, regardless of who pays or receives them. There are several important concepts here.

First, it must truly be a "total" cost analysis – considering not only costs incurred by the utility and the customer, but also costs incurred by the public, the society, or the planet.

Second, it must be a life-cycle analysis. Comparisons of short-run utility marginal cost to long-run or short-run customer costs are not meaningful. MECO is a growing utility, and it is in a position to defer or avoid new generating resource development. Looking only at short-run costs is, by its very nature, shortsighted.

Finally, many of the costs of utility supply and benefits of non-utility resources are difficult to quantify. I include in this the land use impacts, air quality impacts, greenhouse gas emissions, employment impacts associated with imported fuel use compared with domestic labor content, and national security impacts. The Commission needs to apply some judgment, recognizing that there are local benefits to using resources with a greater local (labor or energy) content, and to apply appropriate evaluation techniques to these values. Some regulators have applied flat percentage benefits to renewable and efficiency resources to take these difficult to quantify elements into account. I believe that fuel cost savings (i.e., any combination of waste heat utilization, renewable resources, and energy efficiency) should be given favorable consideration in any such evaluation.

Q. Do you believe that there are significant economic bypass opportunities in Hawaii?

A. Yes, because Hawaii is so dependent on oil for electricity generation. The example I gave earlier, of only a few percent of the energy content of oil providing useful work indicates the scale of improved efficiency that is possible. Let me expand this to an extreme example. A customer can use a CHP system to produce electricity at up to 85% net efficiency (after measuring the value of the water heat that is utilized), compared with utility generation at 35-40% efficiency.

To take this example a step further, the customer can then use that efficiently generated electricity to operate fluorescent lighting at 50% net efficiency instead of incandescent lighting at 12% net efficiency. The customer that does this is achieving fifteen times the useful work per unit of fuel that the user of an incandescent lamp relying on utility service achieves.[4] Applying appropriate pricing policies that help to achieve this efficiency should be a goal for the Commission.

Q. How would your recommendations help to achieve the outcome you describe, with a customer using more efficient generating technology AND a more efficient end-use?

A. Establishment of generation impact fees will cause customers to both choose more efficient end-use equipment (to reduce the number of kW of generation that is required) and to give serious consideration to the installation of CHP equipment to meet that (reduced) capacity need. Under the current system, a developer looking at first cost as their principal guide to investment would be more likely to install the incandescent lamp and connect to the utility grid for service, since the former costs less and the latter costs nothing.[5]

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[4] There are several ways of measuring cogeneration efficiency. A typical CHP system has about 85% total thermal efficiency. This can be viewed as a combination of 36% efficiency making electricity and 120% efficiency making process heat, but it is more accurate, in my opinion, to measure the alternative of producing process heat at 85-90% efficiency, and then assigning the balance of fuel use to electricity generation.

[5] It might be worse than "free" to connect to the grid for an inefficient structure. Under MECO's current line extension policy, the allowance to the developer is five times annual expected revenue. A less efficient structure receives a larger line extension. It might actually be in the developer's interest to intentionally build an inefficient structure in order to reduce the developer's contribution to the line extension.

Q. What about uneconomic bypass? Is this also a possibility?

A. Yes it is, but not one that I consider very serious in most of Hawaii. Uneconomic bypass occurs when a customer incurs more cost to meet their own energy needs than the utility would incur to serve those same needs. This can happen on systems where long-run incremental cost is lower than system average costs, if care is not taken in rate design. However, the risk of uneconomic bypass can be avoided through some of the methods I proposed in this proceeding – establishment of appropriate impact fees for new customers, requiring long-term contracts from new large customers, and reforming rate design to more accurately reflect incremental costs.

I again stress that the key should be measuring long-run bypass costs against long-run utility costs, not merely to compare short-run utility costs to long-run customer costs for bypass. And the comparison needs to consider all of the quantifiable social and environmental costs and benefits I discussed above.

Q. Is there a rule of thumb that you use in estimating whether bypass is economic or uneconomic on a system like those in Hawaii?

A. Yes, in evaluating stand-alone or CHP alternatives, I do. If the customer's incremental capital cost for generating resources is no greater than the utility's incremental cost for generation capacity, and the customer's fuel efficiency is equal to or greater than the utility's fuel efficiency, bypass is likely to be economic. In this algebra, I am inherently assigning approximately equal value to the utility's incremental transmission and distribution cost and losses, on the one hand, and the cost of providing standby and maintenance service on the other. If the customer can use the waste heat from a CHP system, it can afford a higher cost per installed kilowatt than the utility incremental cost of generating capacity. Where renewable resources are involved, obviously the algebra becomes more complicated, because fuel costs are radically different, and the need for standby service can be more complex.

In general, I would expect that customers with either renewable resource potential or CHP opportunities, and loads large enough to invite competitive-sized generating resources (say 200 kW and above), bypass is likely to be cost-effective in many locations in Hawaii, simply because the cost of fuel is so high that the productive utilization of waste heat is very valuable.

Q. Are other types of bypass also likely to be economic in Hawaii?

A. Yes. First and foremost, energy efficiency is extremely cost-effective in Hawaii. With fuel costs approaching ten cents per kilowatt-hour in Hawaii's oil-based generating system, efficiency measures are extremely attractive here. The policies I recommend to encourage distributed generation will also encourage efficiency.

Second, customers that have significant renewable energy potential are logical bypass candidates. The most obvious of these is solar water heating, substituting solar energy in direct application for what would otherwise require utility energy. However, property owners with significant wind potential may be able to displace a significant portion of their electricity demand with wind energy. The same policies I recommend for encouraging distributed generation will encourage customer-site renewable energy.

Q. Are there times when bypass meets your definition of "economic" but would impose adverse impacts on the utility and/or its other customers?

A. Possibly, particularly in the short run. If the short-run savings to the utility from generating and distributing less electricity are smaller than the revenue loss, then bypass creates rate pressure. The Commission is charged with allocating that deficiency either to customers or to shareholders, and there are valid arguments for both approaches.

To the extent that the Commission allows the utility to shift the contribution to fixed costs formerly by customers that bypass to other captive customers, there may be adverse rate impacts. I believe in Maui that this would be a short-lived phenomenon, since MECO is a growing system with long-run marginal costs (including environmental costs) that exceed current embedded costs, as shown in CA-201.

Q. When is bypass undesirable?

A. Bypass can be undesirable for several reasons. First, if the revenue loss from the bypassing customer exceeds the avoidable long-run costs to the utility, there will be permanent rate pressure to other customers caused by bypass. This is best dealt with through progressive rate design that recognizes long-run marginal costs in setting marginal rates for service.

Second, if the emission regulations for small distributed generating resources are less stringent than for utility-scale resources, there may be adverse environmental impacts. Third, there are local impacts of distributed resources, including visual pollution, noise, vibration, air emissions, and fuel transportation and storage that may be undesirable.

Q. Are you aware of the potential bypass on the island of Lanai, where MECO is paying a large customer to not bypass the system?

A. Yes I am generally familiar with this issue.

Q. What useful information does this situation bring to this docket?

A. First and foremost, I consider this to be the result of relatively poor connection policies and contract policies. As I understand it, MECO acquired the system from the previous owner, and invested a significant sum to upgrade the generation system to provide more reliable service to the changed island economy. It did so in expectation of revenues from the new hotels, but did not require the customer to make a comparable commitment.

It could have required contribution in aid of construction designed to recover the above-market costs of this system upgrade, but did not. This was the first mistake. It did not require that the customer execute a long-term contract for service. This was the second mistake.

Because MECO failed to secure a long-term contract, and now is faced with a revenue requirement that exceeds the cost of the customer's competitive alternative, MECO has been forced to offer concessions to the customer.

In some ways, this is the flip side of monopoly power that a utility can exercise if allowed price discrimination, precisely the type of market power than I fear a utility engaging in the CHP market might exercise. A large customer on a small system has market power, and can force the captive seller to meet its terms and conditions or face a loss of market share. The hotel operator on Lanai has apparently done so. It's little different from the way that Wal-Mart treats many of its suppliers – you either meet our demands, or we'll go elsewhere -- AFTER the supplier has invested in production capacity to meet Wal-Mart's demand..

Q. In your opinion, what is the best way to handle a situation like this?

A. The utility made the error to not require a long-term contract, and should be held responsible. The best way to do this is to permit the utility to file lower tariffs for <u>all</u> of its customers, reflecting a write-down of the above-market book cost of its system. This is how the competitive world deals with sellers of resources with above-market costs; for example, the telecommunication provider Global Crossing and other companies invested in a worldwide fiber optic system that could not generate enough revenue to cover costs, and through restructuring, those facilities are now providing low-cost service to all customers desiring that service. The utility would be under pressure to cut its costs in a way that would benefit all consumers.

To allow the utility to reduce prices to one customer, and raise them to another, would be the worst possible result. This would be allowing the utility to operate as a "discriminating monopolist," the worst possible form of enterprise.

As I understand it, the Commission has allowed a competitive discount to the customers with a competitive option, but is requiring that MECO absorb the discount, not allowing it to be shifted to other customers. This is a compromise between the "economically" correct response and allowing the utility to engage in discriminating monopolism. I have no reason to doubt that the Commission considered all issues when granting this approval, and deemed it to be in the public interest considering all factors.

MECO HAS MARGINAL GENERATING FACILITY COSTS THAT EXCEED AVERAGE COSTS, AND IF NEW DISTRIBUTED RESOURCES CAN BE DEVELOPED AT LOWER COSTS, THE PUC SHOULD FACILITATE THIS

Q. What is the average cost of MECO's current generating facilities?

A. As of the last general rate case (Docket 97-0346) the average cost of MECO generating facilities was $687 per kilowatt. This is computed by dividing the production rate base of $143 million by the generating capacity of 209 megawatts. This calculation is shown in my Exhibit COM-201.

Q. How much did MECO estimate that new generating facilities would cost at the time of it's last Integrated Resource Plan?

A. In the 2000 IRP, MECO estimated that peaking units would cost $1,463/kW to build, and that a baseload power plant would cost $1,559/kW. These figures are expressed in

1998 dollars and do not include taxes or allowance for funds used during construction; I estimate that these additions would increase these figures into the $1,700/kW range.

Q. What is the current estimated cost of MECO's new generating facilities that are planned for the balance of this decade?

A. MECO currently estimates that it's Maalaea 18 unit will cost $2,417/kW to construct, and that the Waena 1 unit will cost $3,525/kW.[6] These figures average $3,000/kW, which is substantially higher than the cost that was estimated a few years ago, and four times the average cost of existing generation.

Q. What will happen to MECO's non-fuel revenue requirement if these new units are built?

A. MECO will have higher rates than if these units can be avoided.

Q. What about MECO's transmission and distribution costs? Are these also rising?

A. Yes. MECO's last marginal cost of service study indicated that the marginal cost of transmission and distribution capacity totaled $7.49/kW/month, compared with an

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[6] Response to COM-Companies-SOP-IR-11

average cost of existing transmission and distribution facilities of $5.48/kW/month. While the difference is not as dramatic as for generating facilities, this is still a 37% increase in the cost of delivering power compared with the cost of existing facilities. I expect that inclusion of the proposed new transmission to integrate the Waena site to the MECO grid would exacerbate this difference.

Q. When marginal costs are higher than average costs, what does load growth do to the utility's rates?

A. By definition, if marginal cost exceeds average cost, rates will tend to go up, unless they are offset by some other factor. While MECO's cost of debt and equity capital has probably declined since the last rate case, and this is clearly one offsetting factor, I expect that MECO will be seeking a rate increase in conjunction with the completion of the M-18 unit, and will seek another rate increase if the W-1 unit is built.

Q. What impact does the addition of new customers and new load have on existing customers under these conditions?

A. The addition of new customers requires additional generation, transmission, and distribution plant and the associated cost. This will bring upward pressure on rates. The addition of new load, even at existing customer locations, will require at least additional generation facilities, and probably additional transmission and distribution investment, and cause upward pressure on rates.

Q. How can distributed energy resources mitigate this rate pressure?

A. Distributed energy resources benefit existing ratepayers in many ways. First, to the extent that high-cost new resources can be deferred or avoided, these costs do not create rate pressure. Second, if located in areas where transmission and distribution expansion can be avoided, distributed energy resources help to reduce these costs.

Q. Has MECO used these characteristics of distributed energy resources to avoid transmission or distribution costs in the past?

A. Yes. MECO acquired and relocated the former Lanai units 7 and 8 to Hana. This was done in order to avoid an expensive transmission upgrade. The cost of the generating units was less than $1 million, compared with an estimated $20 million cost to reinforce the transmission system.[7]

Q. Are distributed resources better matched to the load growth of a system like MECO's than central generation?

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[7] Response to COM-Companies-SOP-IR-8

A. Yes. MECO's load is growing at a rate of about 3 - 5 megawatts per year. The central station facilities that MECO's IRP finds most economical are 60-megawatt combined cycle units. Each phase of these is about 20 megawatts – enough to serve about four years of load growth. By contrast, distributed resources come in much smaller unit sizes, better matched to the load growth on the MECO system. MECO estimates that these units would be developed at a rate of 1 - 4 megawatts per year[8]; I believe this can be accelerated with progressive policies regarding impact fees, standby service, and technical assistance.

COMPETITIVE ALTERNATIVES TO UTILITY SERVICE

Q. Please describe in general terms the competitive alternatives to utility service that you believe the Commission should consider in this docket?

A. I believe the entire range of supply-side and demand-side options that constitute "distributed energy resources" should be considered as potential alternatives in this docket. These include:

- CHP with use of waste heat
- Self-Generation without use of waste heat
- On-Site Renewable Energy (e.g. solar water heat)
- Off-Site Renewable Energy (e.g., wind farm)

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[8] CHP Application, Exhibit A

- Energy Efficiency Equipment and Appliances
- Efficient Building Design
- Alternative Fuels such as propane, SNG, and biomass

I discuss several of these in greater detail below.

- CHP with Use of Waste Heat

Q. Is the use of Combined Heat and Power (or cogeneration) a useful alternative to use of utility generation that the Commission should encourage in this docket?

A. Yes. CHP is a proven technology that is applicable to many loads in Hawaii. In particular, Hawaii's hotels have a large demand for both electricity and for hot water, and where these two demands co-exist, there is an opportunity to achieve greater fuel efficiency than the utility can achieve with central power plants.

Q. Please briefly describe the kinds of CHP units that are applicable to Hawaii, and the kind of fuel and economic savings that are achievable?

A. Typical packaged skid-power units are available in sizes beginning about 100 kilowatts. These typically consist of an internal combustion engine and a hot water system. They can achieve total fuel efficiency of about 85%, compared with utility fuel conversion efficiency of 30% - 45%.

Q. How would your proposed policies help to achieve the goal of greater reliance on CHP systems?

A. The proposed hookup fees would cause new developers of large facilities to more seriously consider CHP to meet their electrical and water heating requirements. In many cases, the economics are already attractive, but by internalizing the rate impacts caused by load growth, many additional projects would likely come forward.

Additionally, the approach I recommend to the design of standby rates would ensure that these customers that do partially rely on their own generating resources make a fair contribution to the utility system for the occasional use of utility resources.

- Self-Generation Without Wse of Waste Heat

Q. In your opinion, is self-generation on a stand-alone basis, without use of the waste heat, a viable alternative to central station electricity supply?

A. Generally not, given current technology. There may be some exceptions in remote areas, when the cost of extending utility distribution systems is considered, but for most customers, the cost of building and maintaining a power plant, and either paying for standby and maintenance service or doing without it will exceed the cost of buying power from the utility. Stand-alone power plants are typically no more efficient that the average "fleet" mix that the utility has, so there are unlikely to be fuel savings. The only exception to this might be the use of emergency generators as "peak shaving" units, to reduce dependence on the utility at the time of system peaks. Efficient rate design can encourage customers having such devices to use them when it is most beneficial to the utility.

I do not consider this option to be an important consideration for the Commission in this proceeding. The goal should be to focus on options that reduce Hawaii's dependence on foreign oil.

- Off-Site Renewable Energy (e.g., wind farm)

Q. What types of off-site renewable energy resources are most applicable to Hawaii?

A. Two types come to mind quickly; the first is wind energy, which is viable in specific locations that may be separated from load centers. The second is biomass-fueled generation, which is an historic component of Hawaii's generation mix.

Q. Should these resources be encouraged?

A. Yes. I will focus on wind generation, because I think this industry has matured to the point where it can begin making substantial contributions in Hawaii.

Q. How would wind energy integrate with the Hawaii utility systems?

A. It could be done in either of two ways. First, the utilities could acquire (by ownership or contract) wind energy resources, and integrate these directly into their system operations. I think this is desirable, and should be encouraged. The second would be for individual customers to install wind generators, and then rely on the utility for supplemental service when the wind is not blowing.

Wind energy is now widely recognized as having a "capacity credit" to reflect the fact that wind resources often provide peak load relief to the utility. My own research on this topic presented in Docket 7310 showed that a capacity credit approximately equal to the capacity factor of the wind resource was appropriate.

In any event, wind resources would significantly reduce oil consumption, even if there were no capacity benefit, and at current oil prices, the economic savings would be significant.

Q. How would your proposed policies encourage wind generation?

A. The primary encouragement would be through the development of a standby rate approach that recognizes the capacity value of wind generation. However, I think it fairly likely that utility acquisition by ownership or contract will be the larger force for wind energy development in Hawaii, and the Commission should utilize the IRP process to guide decision making in that regard.

- On-Site Renewable Energy (e.g. solar water heaters)

Q. What types of on-site renewable resources are feasible in Hawaii?

A. There are several types. Historically, much of Hawaii electricity came from biomass, in the form of bagasse, or sugar cane waste. Solar water heaters are the most common renewable energy resource, and the saturation of these could be greatly increased with proper public policy towards distributed energy resources. Other options include solar photovoltaic electric generation, solar-thermal electric generation, use of biomass or other waste materials.

Q. What are the benefits of on-site renewable energy resources?

A. First and foremost, these resources reduce Hawaii's dependence on imported fossil fuel. They generally substitute local labor content for imported fuel content, and therefore strengthen the state economy. To the extent that resources reduce peak demand, they also significantly reduce capital costs for the electric utility; solar water heaters are particularly attractive in this regard, since Hawaii's hot water use typically peaks at the same time as the utility system coincident peak demand..

Q. How would your proposed policies help to encourage the use of on-site renewable energy resources?

A. As previously discussed, the hookup fee would be a strong incentive to builders to install solar water heaters, making these distributed energy resources more ubiquitous in Hawaii. In addition, the establishment of fair, just, and reasonable standby charges would ensure that owners of renewable resources could secure reliable service for their energy needs, and make an appropriate contribution to the utility system capital and operating costs.

- Demand-Side Options

Q. You also identified energy efficiency equipment, energy efficient building design, and use of alternative fuels as viable alternatives to utility service. How would your proposed policies and standards affect these resource alternatives?

A. First, by applying a connection charge to new homes and businesses, the buyer of the original equipment would have a strong incentive to choose more efficient equipment. Second, by pricing incremental usage closer to incremental cost, the payback period on equipment investments would be shortened. I expect that these would encourage both efficiency and on-site renewable resources, such as solar water heaters. By putting use of new electrical generating facilities on a level playing field with other alternatives that are priced at market-clearing prices (such as propane), these policies might encourage the use of alternative fuels where these have lower marginal costs than new electrical generating facilities.

A "VIRTUAL" POWER PLANT FOR STANDBY AND PEAKING

Q. What does the term "virtual power plant"refer to?

A. The term has emerged to describe a process of knitting together existing customer emergency generators into a viable utility reserve resource to meet extreme conditions. In Maui, for example, the County has emergency generators at several locations, the hospital has emergency generation, and many of the large customers have emergency generators. A virtual power plant would provide for the coordination of these units to provide supplemental capacity to the grid under circumstances where the alternative would be a loss of load and localized blackouts. Basically, these units would serve the emergency needs of all ratepayers, not just the ratepayers at whose facilities they are located.

Q. How would such a system be developed?

A. There are several steps to the process. The generators would need to be fitted with synchronization equipment and safety devices so that they can operate in parallel with the utility system. A coordinated telemetry and centralized dispatch system would need to be developed. Contractual arrangements would be required for the units to be operated for system benefit rather than private benefit. Finally, there may be air emission restrictions that would need to be addressed.

Q. Has MECO examined this option in the past?

A. Yes. In response to LOL-SOP-IR-59, MECO described in detail how such a system might work. Mr. Kobayashi addresses this in more detail in his testimony.

Q. Is this type of system desirable?

A. I believe it is, particularly if it can avoid the need for the utility to acquire seldom-used reserve capacity. The highest 50 hours or so of utility load typically dictates the need for additional reserve capacity, and if this rare requirement can be met with existing facilities, the savings are considerable. Assuming that there are 10 megawatts of potential emergency generators on Maui that could be assembled into a virtual power plant, the potential capital savings to MECO could exceed $10 million. Since the units would be used very few hours per year, and the alternative – MECO owned units – would have about the same level of fuel efficiency, the capital savings would not necessarily involve either fuel efficiency or air emission tradeoffs.

Q. Is there experience in Hawaii relying on customer-owned emergency generators to provide system reliability benefits?

A. Yes. In the late 1990's, HELCO was suffering severe reliability problems when the Puna combustion turbine suffered an extended outage, and the Company's generation expansion plan had been delayed. In order to eliminate rolling blackouts that had plagued the island, HELCO contracted with several large customers with emergency generators to switch some of their loads to their own generators during high-load hours. I was involved in researching and encouraging this as a consultant to the Consumer Advocate.

Q. What steps should the PUC take to facilitate such development in Hawaii?

A. In this docket the PUC should direct each utility to inventory the emergency generators in their respective service territories. The cost of developing the needed infrastructure should be estimated. Each utility should report to the Commission on the potential for developing this potential resource.

UTILITY RATEMAKING TO ENCOURAGE AND FACILITATE DISTRIBUTED ENERGY RESOURCES

Q. What issues do you address with respect to ratemaking to facilitate distributed energy resources?

A. First I discuss a few elements in ratemaking history, to provide a context for the current opportunities facing Hawaii. I then discuss four specific areas where I believe changes are required to encourage efficiency and distributed energy resources. These are impact fees (connection charges) for new and expanded loads, reasonable standby rates to partial-requirements electric customers, and reformation of rate design to recognize the cost structure of service in Hawaii and better align customer incentives with utility costs. I recommend that the County be authorized to wheel power between County facilities, to prevent the uneconomic need to construct duplicative distribution facilities. Finally, I propose consideration of a performance-based ratemaking system to align the utility's profit incentives with the goals of its customers for reliable service at low prices.

A. Historical Elements Of Ratemaking

Q. What elements of regulatory history do you consider most important to consider in the context of distributed resources?

A. First and foremost, there is the distributed energy history of the neighbor islands. I also discuss how utilities subsidized line extensions in order to achieve universal service, and the same principles can now apply to prevent inappropriate subsidies to growth. Finally, I discuss how we have moved from a declining cost industry to an increasing cost industry, but the rate designs of the Hawaii utilities do not recognize this cost relationship.

Q. How did distributed energy resources form the basis for the neighbor island power systems?

A. Most of the major communities on the neighbor islands grew up around sugar plantations, and the first electric generation was often at the mills. Prior to statehood, the mills provided power to the surrounding community businesses and to their employees. This allowed for the efficient use of capital, use of renewable fuels, and provided community benefits. There were some diseconomies and some reliability problems, but compared with some other rural areas in the United States, Hawaii actually saw benefits of electrification fairly early. Eventually, the Island economies grew to where "real" utilities were desirable, and the current systems ultimately took over and integrated the previous distributed systems.[9] The point of this is that Hawaii has a rich history of using distributed energy resources, and does not have the "fear" of such resources that other communities might have.

Q. How did public policy lead to subsidies to expansion of electric service?

A. Public policy has encouraged universal service, and in order to achieve this, line extension policies were approved by the PUC that provided new customers with access to the utility system with little or no capital contribution in aid of construction. Hawaii's line extension policies were (and are) fairly generous. In a declining cost industry, as existed prior to the 1970's, this probably made sense. A larger number of customers and larger load helped to spread the fixed costs of the utility over greater sales. New power plants cost less than existing power plants. Under these circumstances, increasing the number of customers and the level of utility sales reduced costs for existing customers.

Q. Is this still justified today?

A. No, probably not, and for three separate reasons. First, we have an increasing cost industry, where new electric facilities cost more than existing facilities, and growth in

9 Final integration on Kauai waited until the aftermath of hurricane Iniki; the Kauai Electric system had five different distribution voltages, all remnants from the plantation power era. After Iniki, a more modern distribution system was constructed.

customers and load drives rates higher for existing customers. Second, to the extent that modern "growth management" tools are desirable in Hawaii, a generous line extension policy tends to encourage sprawl, while a stricter policy encourages more compact development. Finally, and the real focus of this testimony, is that a more progressive line extension policy can encourage greater utilization of low-cost, high-reliability distributed energy resources and energy efficiency.

Q. What changes to the line extension policy do you recommend?

A. At a minimum, the subsidies built into the current system should be eliminated. New customers add more to cost than to revenues for the utility, and should pay a connection charge (impact fee) designed to recover this shortfall at the time of connection to the system. My Exhibit COM-201 looks at the MECO marginal cost study from its last rate case, updates it only for the higher cost of new generating facilities, and estimates that new customers pay only a fraction of the cost of the generation, transmission, and distribution costs the utility incurs to serve them.

B. Impact Fees (Connection Charges) and Credits

Q. How do you propose that this shortfall be collected?

A. I recommend a new customer generation impact fee based on the connected load of customers, designed to recover in a lump sum the shortfall between marginal and embedded costs. I estimate for MECO that this would be about $2,000 per kilowatt of new load under current ratemaking practices, or about $10,000 per new residence (based on 5 kW of diversified peak demand). I also propose that MECO include in its DSM program a series of incentives to customers that install state-of-the-art efficiency and renewable energy measures, so that it is a balanced program of connection charges and credits -- customers that go far beyond the requirements of energy codes would be able to "earn back" much or all of their connection charge..

Q. Why do you recommend a lump sum approach?

A. There are several reasons. First, the utility incurs these costs as capital expenses, so there is congruity from a cost causation perspective. Second, by concentrating this charge at the time the building is constructed (or expanded or modified), the customer has a direct incentive to make cost-effective investments to reduce electricity demand. This includes all of the options discussed above, including on-site CHP systems, on-site renewable resources like solar water heating, and the installation of. energy efficiency measures. Any of those options involves capital expenditures by the customer or developer, and this lump sum approach puts these on a more level playing field with utility electric service.

Q. Does this approach offer cost savings to consumers as a whole?

A. I believe it does, primarily because consumers building new structures typically have a lower cost of capital than the utility does. New homes are typically financed with 80% or greater debt ratios using long-term mortgages, with interest rates currently below 7%; that interest is deductible for income tax purposes. The utility, on the other hand, has a cost of capital (including income taxes) of about 13%, and the utility bill payment is not deductible for residential consumers, so the consumer has to pay not only the utility's income tax (embedded in the rate) but must make the payment with after-tax income. The table below compares the cost to a consumer of financing a $3,500 energy investment using the home mortgage vs. using utility financing. The savings to consumers are very significant.

Benefit of Using Connection Charges vs. Utility Capital Financing

First Year Annual Cost Of $3,500 Solar Water Heater	**Residential Consumer Owner**	**Utility Financing**
Before Personal Income Tax	$384	$718
After Personal Income Tax	$335	$718

Q. Does the same analytical approach also apply to commercial and industrial development?

A. It's not quite as robust, in part because the cost of debt for commercial development is somewhat higher than for residential customers, and in part because businesses can deduct their utility bills as ordinary business expenses, so the double-taxation issue is less severe. However, it is precisely these customers that often have the best distributed generation and energy efficiency opportunities, so it is crucial to give them effective price signals.

Q. Why shouldn't the efficiency measures simply be required in energy codes for new development?

A. Efficiency codes can produce beneficial results, and I support adoption of strong codes, but they have several shortcomings. First, they require enforcement, and that can be somewhat sporadic. Second, they do not really invite innovation, and many energy saving opportunities involve deployment of new technologies. Most important, builders prefer flexibility in design, and if impact fees can provide this to builders while still protecting other customers from adverse impacts, it protects consumer choice. An impact fee puts the onus for efficiency on the builder, and I expect that creative solutions will evolve.

Q. What is your experience with utility impact fee and connection charge programs?

A. I have been involved in the development of several such programs, and the results have been quite dramatic. In one case, a utility service area went from less than 10% participation in a beyond-code efficiency program to more than 90% participation in less than one year. I presented a paper on my involvement and findings at an international conference on energy consulting held in Austria. A copy of that paper is included in my Exhibit COM-202.

Q. How should a generation impact fee be designed?

A. There are two approaches to setting impact fees. The first is a "full-cost" impact fee, and the second is a "marginal minus average" approach. Both have merit in the context of Hawaii's energy utilities.

The most commonly used method among municipalities in implementing impact fees for transportation, water, sewer, and other utility services is what I call a "full cost" impact fee. These are designed by computing the new facilities required to maintain existing levels of service in the face of growth, estimating the cost of these facilities, and dividing by the units of growth that are anticipated. The result is an impact fee that fully recovers the incremental capital expense of facilities needed to provide service to new customers without adversely impacting existing customers.

The second approach is to estimate the amount of capital investment needed to serve growth, but then to subtract the amount that will be collected through existing rates. The impact fee is the difference between these two. This approach is more commonly used in the electricity and natural gas industry. MECO has such a connection charge for its distribution line extension tariff, Rule 13. This provides for partial payment by the utility of up to sixty months estimated revenue, and places the burden for any additional cost on consumers. However, this applies only to the extension of distribution lines, not to the development of generation or transmission facilities.

Q. Describe how a generation impact fee would be calculated using the first approach, the full-cost impact fee?

A. The cost per kilowatt of new generating capacity would be the foundation of the calculation. MECO identified in its response to COM-Companies-SOP-IR-11 two potential new power plants that it might construct if demand requires additional generating capacity:

Unit	Capacity (kW)	Cost ($)	Cost/kW
Maalaea 18	18,000	$43,500,000	$2,416
Waena 1	20,000	$70,500,000	$3,525
Total	38,000	$114,000,000	$3,000

For purposes of this testimony, I will use the average figure of $3,000. A kilowatt of capacity at a central station does not quite equate to a kilowatt of demand at the customer's premises. First, a utility must provide reserves for generation capacity, typically about 15%. Second, there are line losses between the generating plant and the customer's premises, typically 5-10%.[10] Finally, there is customer diversity, meaning that not all customers have their personal peak demand at the time of the system peak demand, and the utility can factor down the generating capacity required in anticipation of diversity of demand on the system. This varies significantly by customer type and customer class, ranging from a very small amount of diversity for large-volume users to more significant diversity in the residential and small general service classes.

I will assume, for the sake of simplicity, that the additional capacity needed for reserves and losses is offset by the capacity savings that results from diversity. This means that the full-cost impact fee to a new developer would be $3,000 per kilowatt. A commercial

[10] HECO response to CA-SOP-IR-19

development with a 500 kilowatt connected load would pay $1.5 million to connect to the system under this approach. If the customer judged that they could reduce their dependence on the utility for less than the cost of the utility meeting their needs, they would do so, and the utility would avoid the incremental cost. This would make CHP systems more attractive at the time of construction, which is the optimal time to install a new energy system. A residential customer connecting a new home with a 10 kilowatt connected load would pay $30,000 for generating capacity. By participating in the Energy Star home program, installing a solar water heater and other energy-saving measures, (or by installing a solar photovoltaic system) the customer could reduce that connected load to 5 kilowatts, and the customer would pay only $15,000 for their generation impact fee.

A similar calculation could be made for transmission capacity, which, like generation, is currently not a part of the current line extension policy. Finally, the current sixty-month allowance that is included in the distribution line extension policy would be eliminated.

Q. Is there anything about a full-cost impact fee approach that is inequitable if applied to Maui Electric?

A. Yes. Currently MECO rates are set to recover the capital cost of embedded generating facilities through rates paid by customers. A portion of this is associated with the return, depreciation, and taxes on existing power plants. If a new customer paid "up front" for 100% of their generating capacity needs, it would be inequitable to <u>also</u> charge them for a share of the capital cost of existing generating plants in rates. It would be more equitable to allow them a credit on their bill for the amount of generating plant investment included in rates for existing facilities. This could be done, but would be a significant restructuring of utility rates to provide a separate credit for new customers to reflect prepayment of generating plant costs. In my opinion, this approach is complicated and undesirable. Fortunately, there is an easier way.

Q. How do municipal utilities typically handle this issue?

A. In my experience, many municipalities fund capital expenditures on a pay-as-you-go basis out of rates or other funds, and do not use a "rate base" approach for funding these facilities. Therefore the customer that pays an impact fee then pays rates that do NOT include significant capital amortization expenses. The rates pay for operation, maintenance, renewals and replacements, overhead, and other expenditures, but often not for a return on rate base.

Q. Is there another approach that accounts for the fact that new customers will pay rates that include current costs for power plants?

A. Yes. A "marginal minus average" approach would charge an impact fee only for the portion of the cost of new generating facilities that is not already reflected in current rates. New customers would pay this portion of cost at the time of connection, and then would pay the same rates as other customers, including a portion of the return on the generating plants. This approach would not require any new ratemaking conventions. It is the basis of the current distribution line extension policy for MECO.

Q. Have you estimated the connection charge that this approach would imply?

A. Yes. My Exhibit COM-201 shows the production rate base as of the last MECO rate case (Docket 97-0346) and the current generating plants. The total rate base was $144 million, divided by 209,100 kilowatts of capacity produces an average rate base of $687/kW. This would be deducted from the incremental cost of $3,000/kW, to produce an impact fee of $2,313/kW for new customers (adjusted for diversity, as appropriate).

Q. How would the utility account for the revenue from this charge?

A. It would be accounted for as a contribution in aid of construction, and deducted from rate base in determining rates of general application, just as is now done for distribution system contributions. Under this approach, the average cost of production rate base would remain at $687/kW in this example. This is the necessary level of contribution to prevent subsidies of new customers by existing customers. Once this fee was paid, the new customer would pay the regular utility rates, thereby contributing to the cost of existing and new generation included in rate base, pay for renewals and replacements. Over time, new consumers (like existing consumers) would pay the full costs of their electric service.

Q. What would you expect the result of either of these approaches to be?

A. I would expect builders and developers to be more likely to choose size their electrical needs more carefully, install CHP systems, install renewable energy systems, and pay more attention to energy-efficient design and energy-efficient appliances and equipment.

Because the current subsidies of new customers by existing customers would be eliminated, rate increase pressure on existing customers would be largely mitigated. Inflation of operating costs, and volatile fuel costs would still affect rates, but the cost of new generation would not be a source of rate pressure as it is today.

Q. What would the effect of this approach be on consumers?

A. Existing customers would pay lower rates over time, because they would no longer be subsidizing new customers. New customers would have significant up-front capital expenses. If they did not improve the efficiency of their structures, they would clearly pay more, but if they chose more economical ways to meet their energy needs, they might actually pay less over time when considering the sum of impact fees and energy costs over the life of the structure. For residential consumers, it is very likely that the net after-tax cost would be lower due to the cost-effectiveness of efficiency measures and solar water heaters, coupled with the tax advantages of mortgage financing compared with utility financing discussed above.

Q. What about renters? How would they be affected?

A. Renters typically suffer from high utility bills, in part because the person choosing the energy-consuming equipment in their home (the landlord) is not the person paying the utility bill. An impact fee would at least align the interest of the owner of the building and the user of the building. The owner would be more inclined to choose efficient appliances, solar water heaters, and other electricity-saving investments if an impact fee were imposed.

Q. What would the effect of this approach be on the utility?

A. It would clearly allow the utility the opportunity to defer construction of some very high cost generating facilities if customers chose options that reduced their dependence on the utility. At a minimum, it would provide a source of capital to the utility to fund system expansion that would replace capital it would need to raise on debt and equity markets. Over time, however, the utility rate base would cease to grow as fast, and the utility would need to adapt it's capital management policies to reflect this, most likely by increasing the dividend payout ratio. In cost of capital terms, the yield would increase, and growth rate of the dividend decrease.

Q. What would the effect of this approach be on providers of distributed generation equipment?

A. This approach would allow DG vendors to compete on a level playing field with new central utility generating facilities in the market to serve new (and expanding) loads. Customers would see a connection charge that reflected the cost of new facilities, and might choose to explore DG as a partial or full alternative to utility service. As long as the capital financing sources available to the DG market were competitive with those available to finance the utility impact fee, the competition would be more fair than it is today.

Q. What would the effect of this approach be on utility system reliability?

A. It would have a beneficial impact on reliability, by replacing one large power station with a combination of lower loads and smaller generating resources located closer to the loads. The standby rate design I recommend would provide the necessary incentives for them to do so.

C. Reasonable Standby Charges

Q. What is standby service, and why is this important for customers installing distributed generation equipment at their facilities?

A. Standby service is the provision of electricity by the utility to customers with on-site generation during periods when their own generation is unable to meet their on-site power needs. Standby service is important so that customers building their own generating facilities do not also need to build seldom-used backup generators. The customers receive continuous service, either from their own resources or from utility resources. Since they only use utility resources a portion of the time, the utility can use those resources for other customer needs as well.

Q. What are the types of standby service?

A. Generally standby service is divided into three categories;

Supplemental Service: providing power on a regular basis that is over and above the capacity of the customer's on-site generating facilities.

Maintenance Service: Providing power to customers during periods when their generating facilities are out of service for scheduled maintenance.

Backup Service: Providing power to customers during unscheduled outages of their on-site generating facilities.

I have attached Southern California Edison's standby service tariff as Exhibit COM-203, as an example of the form of a relatively progressive standby tariff.

Q. What options do MECO customers currently have for standby service?

A. The only option is to take service under the otherwise applicable utility tariff, most often Schedule P, and to displace energy and capacity purchases under that tariff. This results in these customers making an excessive contribution to MECO's fixed costs.

Q. Is this tariff the most appropriate way to charge standby customers for the service they receive?

A. I think it is an appropriate way to charge for supplemental service, but not for maintenance or backup service. The needs of standby customers are different from full-requirements customers, and both the utility and the customer could benefit from a different approach to standby rates.

Q. How should the standby tariff be established, and how is that different from the sales tariff?

A. First, I would define two classes of standby service, which I will call "firm" and "best-efforts" service. Both tariffs would have lower fixed costs allocated to them than full-requirements tariffs, offset by higher variable charges than the current rates. The idea would be that if customers used standby service very sparingly, they would pay only a modest amount for service, but if they relied on it heavily, they would pay a higher price than full-requirements customers, reflecting the uncertainty that they place on the utility and the risk that causes for other customers. If the "risks" materialized into a measurable adverse impact on service, the utility and its other customers would be amply compensated for that impact.

Q. Why should the fixed cost associated with firm standby service be lower than for full-requirements service?

A. Customers with self-generation equipment only put a burden on the utility when their own equipment is out of service or derated for some reason. This is a sporadic use of the utility system. For example, internal combustion engines require oil changes on a monthly basis; these can easily be scheduled during utility light-load hours. Assuming that scheduled maintenance of self-generation equipment is required to be coordinated with the utility's own maintenance schedule (a condition I believe is appropriate in a standby service tariff), it is unlikely that the standby demand will come at a time when the utility's system is under stress. Further, with multiple self-generation customers all paying for standby service, the probability of all of them requiring standby service at the same time is vanishingly small.[11]

Assume, for example, that a utility serves four customers each with 90% availability of their on-site generation. If the utility constructed backup generation capacity for <u>one-fourth</u> of the potential standby demand to which it is exposed and charged each customer <u>one-third</u> of the normal fixed charges for doing so, the utility and it's other customers would benefit. The utility's system reliability would increase for other customers, and its rates would decrease. The reliability would increase because the increased generating capacity acquired would exceed the probability-weighted outages that might occur during

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11 This example assumes four customers, each having equipment with 90% availability outside of scheduled maintenance periods. Mathematically, the probability of them all being out of service simultaneously is less than one hour per year. The probability of that simultaneous outage coinciding with a period when the utility system is under stress approaches zero.

peak periods. The cost to other customers would decrease because the incremental revenue from the standby customers would exceed the incremental cost of capacity to provide their standby service.

Q. Is it reasonable to expect that numerous DG systems will be installed, providing for the diversity that you suggest be assumed in setting standby rates?

A. Yes. In it's CHP Application, at page 8, HECO estimated 30 CHP systems on Oahu, 28 systems on Maui, and 18 systems on the island of Hawaii. This is more than enough to provide the kind of diversity that justifies very low fixed charges in standby rates for customers with reliable systems. The approach I propose, with a low fixed charge and high variable cost meets this goal.

Q. Do MECO's current rates apply all of the fixed costs in the form of a fixed demand charge?

A. No, they do not. MECO has identified fixed costs of $19.14/kW in its last cost of service study, but the demand charge on Schedule P is only half this amount. MECO recovers the remainder of the fixed charges in the energy rates, primarily in the first two load-factor blocks. This is normal and proper. Customers with low load factors can "share" capacity, and this rate design recognizes this fact.

Q. Is the current Schedule P rate design a reasonable framework for a standby charge for customers of this size?

A. In general, I think it is. I discuss below the desirability of modifying the three "load factor blocks" into "time-of-use" rates, and with that change, I think the current structure of this rate design would be a good model for a standby rate. The only other change I might apply would be to unbundle the demand charge into a generation component and a transmission and distribution component, and apply the T&D portion as a fixed annual charge, rather than a variable monthly charge.

Q. Provide a hypothetical example of a standby rate that you believe would be appropriate for MECO.

A. The example below is NOT designed to produce a specific target revenue requirement. It is merely designed to show all of the standby rate components, and a rough order of magnitude that is appropriate to each element. The formula I would apply would be to have the fixed component of the standby generation rate recovery one-fourth of the generation fixed cost paid by full-requirements customers, but to set the energy rate high enough that a customer relying on standby service for all of their energy requirements would pay the higher fixed cost of new generation resources, not the average cost of existing resources that are embedded in rates to full-requirements customers. This ensures that customers that use standby service sparingly, and can "share" standby capacity with other standby customers, are treated fairly, but that customers not maintaining their own generation facilities pay an appropriate rate penalty.

Example of Firm Standby Rate	
Customer Charge	$200/month
Generation Demand Charge	$3/kW/month for all standby demand, based on nameplate rating of self-generation equipment
Transmission and distribution demand charge	$3/kW/month multiplied by highest measured standby demand in the previous year
On-Peak Energy Charge	$.10/kWh + incremental on-peak fuel cost/kWh
Mid-Peak Energy Charge	$.06/kWh + incremental mid-peak fuel cost/kWh
Off-Peak Energy Charge	$.03/kWh + incremental off-peak fuel cost/kWh
Maintenance Coordination Requirements:	Customer to schedule all maintenance outside of the 500 highest system peak hours, and in coordination with all other standby customers

Q. What are the key features of this hypothetical rate design?

A. First, the monthly standby charges are relatively modest in months when no standby energy is required. Second, the on-peak energy charge is high enough to make a significant contribution to the fixed costs of generating facilities that provide the utility with firm peaking capacity. Third, even the off-peak energy charge is high enough to make some contribution to fixed costs, so that if a customer relies on standby service for an extended period, they will pay more to the utility than they would as a firm full-requirements service customer; this is appropriate because of the risk and uncertainty they create for the system. Finally, the customer is required to schedule all maintenance to avoid intentionally placing a demand on the utility during a period of system stress.

Q. Why is the time-of-use element in the energy charge important?

A. Distributed generation equipment normally requires relative frequent short service intervals, for example, monthly oil changes. Applying a time-of-use energy charge will both encourage the customer to do such maintenance during off-peak periods, and provide appropriate compensation to the utility and its other customers when peaking resources are needed to provide standby service.

Q. What do you mean by a "best efforts" standby rate?

A. I use this term as it is commonly used in the natural gas industry, to mean an obligation to serve by the utility that comes after all full-requirements and firm standby customers, but prior to any off-system sales or discretionary system maintenance. The utility would be required to operate any available generating resource to meet this obligation, but would curtail service if necessary to preserve system stability to firm customers.

Q. What kind of customer would elect this type of service?

A. I would expect an industrial customer with self-generation equipment to be attracted to this type of rate for their process electricity needs. They would probably choose firm service to their offices and other time-critical processes, but accept a lower quality of service (in exchange for a lower price) for their process needs. If their self-generation equipment failed during a period of system stress, their service under this schedule could be curtailed. A hotel might choose best-efforts service for their water features, laundry, and other "hidden" energy use, while selecting firm standby for their common areas and guest rooms.

Q. Have you also designed a hypothetical best-efforts standby rate?

A. Yes, an example of this is shown below; note that the fixed cost contributions are significantly smaller than those in the firm standby rate above. The reason for this is that the utility does not need to build any facilities to provide this service, so there is no basis for a higher fixed charge. The lower rates shown would still provide a significant contribution to fixed costs, providing a benefit to other customers.

Example of Best-Efforts Standby Rate	
Customer Charge	$200/month
Generation Demand Charge	$1.50/kW/month for all standby demand, based on nameplate rating of self-generation equipment
Transmission and distribution demand charge	$1.50/kW/month multiplied by highest measured standby demand in the previous year
On-Peak Energy Charge	$.06/kWh + incremental on-peak fuel cost/kWh
Mid-Peak Energy Charge	$.04/kWh + incremental mid-peak fuel cost/kWh
Off-Peak Energy Charge	$.02/kWh + incremental off-peak fuel cost/kWh
Maintenance Coordination Requirements:	Customer to schedule all maintenance outside of the 500 highest system peak hours, and in coordination with all other standby customers
Curtailment Obligation	Customer can be curtailed at any time that the utility reserve margin, considering all generation equipment available for service, falls below 7%. Customer can be curtailed at any time that the utility determines that the transmission line(s), distribution substation(s) or distribution line(s) serving the customer is operating at an amperage in excess of a safe level.

Q. In the above example, what gives the customer any certainty that the utility will not declare a distribution line to be overloaded, and arbitrarily curtail the customer?

A. The utility retains the obligation to provide all available service to customers on demand, and this tariff does not change that. Further, the fact that all of the three energy blocks provide a significant contribution to the utility's fixed costs means that providing this service will be profitable to the utility.

Q. What type of contract should be required for standby service?

A. A detailed service agreement should be required for any standby service. It should extend for multiple years for firm standby service, as the utility must plan and build facilities to serve the probability-weighted service requirements. For best-efforts standby service, where no facilities are being built, a short-term agreement may be reasonable, but it must be unambiguous about the risks to the customer associated with this option. Finally, a customer should have the right to a combination contract, for example, providing 50 kW of firm standby (for offices, computers, and other mission-critical functions) and best-efforts standby service for less critical loads.

D. Rate Design Issues

Q. Please summarize the rate design issues you have identified as important in the context of distributed generation and other distributed energy resources?

A. First, I have identified the relationship between fixed costs and fixed charges as important. Second, I compare the marginal costs of service to the average utility system costs, providing context for the importance of encouraging development of distributed energy resources. Third, I propose alternative ways to reflect incremental costs in prices to all customers. I propose specific contract requirements that should apply to large consumers to mitigate the risk they impose on the utility and its other customers. I recommend that the County be permitted to wheel power between different locations for its own needs. Finally, I recommend that the Commission consider performance-based ratemaking practices that would link the utility profits to something other than sales levels.

1. Fixed costs and fixed charges

Q. Does the utility industry have significant fixed costs?

A. Yes. The investment in generation, transmission, and distribution facilities is capital-intensive. Maintenance is not really "fixed" in an accounting sense (it is mostly labor), but clearly maintenance costs do not vary directly with throughput. About half of a utility's total revenue requirement is associated with these fixed costs, with fuel being responsible for most of the variable costs.

Q. How have utilities traditionally recovered their fixed costs?

A. Most utilities recover their fixed costs through a combination of customer charges, demand charges, and energy charges. The first of these is a fixed charge per customer per month, but the other two are variable charges, applying to actual usage of electricity services.

Q. Do other industries recover their fixed costs through variable charges based on usage?

A. Yes, nearly all industries price their products on a per-unit basis, even though much of the cost that makes up that selling price may be fixed. Farmers have land and machinery as fixed costs, but sell their product by the pound, bushel, or box. Airlines have airplanes and ground equipment as fixed costs, but sell service by the seat on each flight. Grocery stores have parking lots, buildings, and refrigeration equipment as fixed costs, but typically charge only for the groceries their customers buy at the cash register. All of these industries recover these fixed costs in the prices of the products they sell.

Q. Are utilities "different" from other businesses in this regard?

A. Yes, but only because they are monopolies; as such they have <u>less</u> need to collect fixed costs in fixed charges than competitive-sector businesses.. Utilities recover a portion of their fixed costs in fixed charges, specifically the customer charge. These typically recover customer-specific costs, such as service drops, meters, meter reading and billing. These type of costs vary with the number of customers served. Typically all other costs are recovered through usage-related charges.

Q. Does the potential for distributed generation create a situation that requires reconsideration of how utility costs are recovered?

A. Yes, because DG customers will use utility service only sporadically.

Q. What differences in rate design are appropriate for serving DG customers?

A. I have recommended above that DG customers pay rates for standby service that have lower fixed charges and higher variable charges than full-requirements customers pay. The reason for this is that the low fixed charges will remove a potential barrier to DG investment, and as I have demonstrated, this investment is very desirable to reduce the need for expensive new generating resources.

Q. What do you expect will be the result of this approach?

A. Low fixed charges for standby service will tend to encourage DG deployment; the higher variable charges will provide incentives for developers to choose reliable equipment, and to use utility service only when really necessary. Maintenance will be a priority for these customers under this approach, and this will enhance the achievement of the cost-saving and fuel-saving benefits of DG.

2. Marginal vs. Embedded Costs

Q. How do MECO's marginal costs of providing additional service compare with it's average cost of providing service?

A. At the time of the last general rate case, MECO estimated that it's marginal costs and average costs were very close, with marginal costs about 8% above average costs. Looking a bit deeper at these figures, however, it showed that the marginal customer-related costs were significantly lower than average costs, while the marginal generation capacity costs were about 30% above average cost. The relevant portion of the Company's exhibit from that rate proceeding is included in my Exhibit COM-201.

Q. Has that relationship changed since that time?

A. I believe it has become more pronounced. At that time, the incremental generating resources were estimated to cost about $1500 per kilowatt; today the estimate is $3,000 per kilowatt. So the incremental costs of new generation have probably increased significantly. If that exhibit were updated today for the MUCH higher cost of new power plants, it would show marginal costs significantly higher than embedded costs. I have performed a simplified analysis of this effect in Exhibit COM-201. It shows that MECO's marginal costs are 30% - 50% higher than its embedded costs. This clearly suggests that load growth will cause rate pressure.

Q. What is the appropriate response of the regulator in a situation where marginal costs exceed embedded cost?

A. Under these circumstances, controlling load growth will produce savings for existing customers. Effective DSM programs are one tool to achieve this, but implementing policies to encourage distributed generation and other distributed energy resources also can mitigate the rate increases that are inevitable if loads continue to grow.

3. Incremental Cost Pricing to Recognize Cost of New Resources

Q. You have proposed connection charges for new customers and expanded loads, in order to recover the portion of the cost of serving growth that is not reflected in current rates. Are there techniques to reflect higher marginal costs in rates of general application for existing customers?

A. Yes, there are several options. It is possible through rate design to get the most price-sensitive components of cost more closely aligned with marginal costs.

In the case of electric utilities, the decision to connect to the utility is all-but-universal, while the quantity of electricity consumed can be price-sensitive. Having lights, refrigeration, and basic appliances is a near-necessity of modern life, but having air conditioning, a hot tub, or a plasma television are more discretionary.

Q. What are the best tools available for the residential class to align marginal costs and marginal rates?

A. Minimizing the customer charge, which applies regardless of usage, preserves the revenue requirement to be reflected in the usage charge. MECO already does this to some extent, having a customer charge that is lower than it's own estimate of either marginal or embedded customer costs.[12] An inverted rate design, that provides all customers with an initial block of usage at one price, with additional usage priced at a higher price reflecting the cost of new resources is another option. Because of the relatively high on-peak coincidence factor associated with electric space heat and air conditioning, I believe that a rate inversion at the 300 - 500 kWh/month level would be appropriate for MECO. Customers without air conditioning and with solar water heaters would not cause this peak demand, and would not experience this rate inversion. I believe this would be less expensive than implementing time-of-use rates for the residential sector, an action that would require an expensive investment in new meters.

[12] In Docket 96-0040, I examined MECO's customer costs, and found that the appropriate level of customer charge based on embedded costs was about 20% lower than the then-approved level.

Q. In the general service sector, can the same approach be used?

A. A minimal customer charge is one appropriate tool for general service customers, since virtually all will connect to electric service anyway. Reducing this charge, and concentrating on the usage charge, will better align marginal rates with marginal costs. An inverted rate design is less applicable to the general service schedules, simply because of the diversity of uses and customer types makes it impossible to set an initial block that is fair to all customers. Some utilities are experimenting with what are called "rolling baseline" rates that provide an initial block to each general service customer based on low costs of vintage resources, and a higher block at a higher rate reflecting the cost of new resources. This is more fair, because each customer gets a customized first block.[13] A more logical approach, however, would be to implement time-of-use rates for general service customers to reflect higher on-peak capacity and energy charges.

Q. Can time-of-use rates be used to improve the rate designs for Schedule J and P?

A. Yes. Currently these rates have three "load factor" blocks. These charge progressively lower rates to customers who use power steadily throughout the month. The problem with this approach is that if a customer's individual peak demand occurs

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[13] BC Hydro is developing a proposal along these lines in response to direction from the British Columbia Public Utilities Commission; Manitoba Hydro has retained National Economic Research Associates to explore inverted pricing for general service customers.

outside of the hour of the system peak, the incentive is to "flatten" demand, which means to use more power during the system peak. Changing this to a time-of-use rate design would improve the incentives to control power demand at peak times. This would be completely compatible with the proposal I have made for standby rates to have time-sensitive energy charges to recover capacity-related costs.

Q. Can you give an example of how the Schedule P rate design changes you suggest would work?

A. Yes. The table below compares a load-factor block approach to a time-of-use approach.

Rate Element	Current Rate (Simplified) (Demand Charge applies to customer non-coincident demand)	Three-Block TOU Rate (Demand Charge applies to Priority Peak Demand Only)	Two-Block TOU Rate (Demand Charge applies to Priority Peak Demand Only)
Customer Charge	$300.00	$300.00	$300.00
Demand Charge	$10.00	$10.50	$12.00
Energy Charge 1	$.07 (200 kWh/kW)	$.085 (Priority Peak)	$.06 (Priority Peak)
Energy Charge 2	$.06 (next 200 kWh/kW)	$.06 (Shoulder Peak)	$.06 (Shoulder Peak)
Energy Charge 3	$.055 (over 400 kWh/kW)	$.055 (Off-Peak)	$.055 (Off-Peak)

Q. How do competitive wholesale energy markets recover the fixed costs of generating capacity?

A. Most of the wholesale markets now operating are energy-only markets, without separately stated demand charges. Sellers recover their fixed costs through variable unit sales.

E. Contract Requirements for Large Customers

Q. What type of contract requirements do you think are appropriate for large customers?

A. I recommend that large customers be required to execute multi-year contracts with advance notice requirements to significantly change their demand on the utility. The required term should be a function of the size of the customer and the rate of load growth projected for the utility system to which they will be connected.

Q. Why is this desirable?

A. Large customers – those using more than 1% of total utility sales – pose a special risk to the utility and its other customers. If such customers suddenly discontinue service, they can leave the utility with a large stranded investment. This can create financial stress for the utility, and if the Commission allows the utility to recover this stranded cost in rates to other customers, creates rate pressure for other customers.

Q. Has there been a recent example of this issue in Hawaii?

A. Yes, on the island of Lanai. After MECO took over the utility system in Lanai, it invested in new generating facilities in part based upon the expected load of two new resort hotels, each of which represented a significant percentage of the total load on Lanai. Having done so, one of the hotels explored a distributed generation option that it determined would be less expensive. Since the customer had no contractual obligation to take power from MECO, the utility would have been left with underutilized generation and transmission facilities. In order to prevent this loss of business and revenue, MECO offered a concession to the customer.

Q. In your opinion, how should a situation like this be handled?

A. A utility should not make customer-specific investment unless it has a reasonable assurance that the customer will remain on the system long enough to amortize the investment. For residential customers, this is immaterial, since if one customer moves out, another typically moves in, and if a house burns down, another is typically built in its place. For large customers, the risk to the utility is much greater. A long-term contract requirement for large customers is the appropriate response.

Q. How should such contracts be structured?

A. I recommend that a contract have an initial term of at least 5-10 years, and that it contain an "evergreen" clause that automatically extends the obligation if no affirmative notice is given to discontinue service. Ideally, the notice requirement would be aligned with the rate of load growth on the system, so that the utility could adapt to the customer's change in load by deferring new investment, and using the soon-to-be-stranded resources to serve additional customers. On the island of Oahu, a 3 year notice requirement would probably be sufficient to allow the utility to adapt it's generation development to a changed load forecast, while a longer notice period might be required on the neighbor islands. On Lanai and Molokai, where other load growth is unpredictable, the contract and notice period should perhaps be tied to the accounting life of the assets.

Q. In your opinion, could the situation in Lanai have been anticipated and prevented?

A. Yes. When asked to provide additional service, MECO could have insisted on either a contract for service, or an impact fee payment to ensure that the incremental cost would be covered. The failure to do so should not create adverse impacts for other customers.

Q. How have other utilities addressed this type of situation?

A. Multi-year contracts are quite common for large customers. The most recent relevant situation is the proposal of the California governor that all large customers should be allowed to give notice to utilities in 2006 that they will seek competitive options for power supply, and then be allowed to actually discontinue utility service in 2009, when the utility contracts with the California Department of Water Supply expire, and each of the large utilities will require additional resources if all of their customers remain on the system. I am aware of numerous other examples of long-term contracts where customer demands are a significant percentage of total utility sales.

F. County Wheeling: Should Maui County, as a DG owner, be allowed to wheel to other DG or non-generation locations?

Q. What is your recommendation on the subject of wheeling of power from one point of production by a non-utility owner of generation to other locations?

A. The only recommendation I have relates to public-sector customers such as the County of Maui. I recommend that MECO be directed to establish cost-based wheeling rates that are available to municipal agencies to move power from a point of generation to a point of consumption.

Q. What is the potential application of such a rate?

A. Maui County is one of the largest owners of generating facilities in the County, along with MECO, HC&S, and Maui Land and Pine. It is possible that Maui County could develop a renewable generating facility or a combined heat and power facility, and it may be most economical to develop one larger facility rather than several smaller facilities. Having the ability to move power from the point of production to other points for consumption would potentially enhance the project viability. This would eliminate the potential need for duplicative distribution facilities.

Q. Why should public agencies be treated differently from other customers?

A. Public agencies are different from other customers for several specific reasons. First, they are permanent components of the community. Second, they have access to tax-exempt debt issuance, and can finance capital-intensive projects more economically than other customers. Most important, since the streets and rights of way along which such lines would run belong to the County of Maui, no "franchise" would be needed for the County to build such facilities; no other customer would have that right. The "natural monopoly" concept dictates that it should be uneconomic to have duplicative lines, so the obvious answer is to offer wheeling services to the County. Finally, any economic savings that accrues from a project developed by a public agency is returned to the public, so even if there is some small loss to the public as utility customers if public agencies wheel power, the economic savings is returned to the same people.

Q. How should such wheeling rates be structured?

A. MECO's unit cost study forms the basis for setting wheeling rates. As shown in my Exhibit COM-201, the Company's embedded full-cost transmission and distribution cost is about $5.48 per kilowatt-month, or about $.015/kWh at a typical load factor. I recommend that initially such wheeling rates be established on an annual multi-year contract basis with an evergreen clause, so that there is no risk to the utility.

G. Performance-Based Ratemaking Options

Q. What is the thrust of your proposal for consideration of performance-based ratemaking options?

A. The recommendations in the preceding portions of my testimony would move the utility away from it's role as a monopoly provider of electricity service, and encourage development of distributed energy resources of many types. The expected and intended effect would be to reduce the rate of utility load growth and utility investment in power facilities. Because the utility's earnings are currently a function of its investment level, this approach would therefore constrain the growth of utility earnings that are now expected by MECO. The proposal to have new customers pay impact fees or connection charges would dramatically reduce the growth in the utility's rate base, upon which its profits are based. If we expect the utility to embrace these changes, we must provide it with a new regulatory framework so that expectations of returns to shareholders can be sanguine.

Q. What types of performance-based ratemaking options should be considered?

A. As an initial discussion, frameworks that separate utility profits from sales volumes are desirable. Mechanisms that reward the utility for the cost savings achieved by its customers, rather than the costs incurred by the utility to serve them are desirable.

Mechanisms that reward the utility for efficiency, rather than for gold-plating should be explored. Examples of mechanisms with desirable characteristics include:

- Rate Cap Regulation
- Bill Cap Regulation
- Portfolio Management Incentives
- Fuel Efficiency Incentives
- Service Quality Indexes

Q. In your opinion, are the current incentives flawed as they apply to MECO?

A. Yes. MECO currently earns a profit on its rate base. The more it invests to serve customers, the more profit it is allowed in the ratemaking process. There is no real incentive to control costs, except for the threat of various forms of bypass. In order to align MECO's incentives with the goals of other ratepayers, an incentive to control costs must be developed. In order to align the interests of new customers in pursuing alternatives to utility reliance with the interest of existing customers in avoiding load growth, a change to a regulatory framework that rewards only utility-provided service should be developed.

Q. Do you have specific experience in the design, development, and implementation of performance-based ratemaking programs?

A. Yes. I helped to design a decoupling mechanism for Puget Sound Energy in 1990, and to design a new power cost adjustment mechanism with symmetrical incentives and penalties for Puget in 2002. I also taught a two-day training in PBR in New Delhi, India, sponsored by the U.S. Agency for International Development. As long ago as 1982, I wrote a paper on changing the incentives built into utility regulation to reward utilities that reduce load growth, rather than those that increase their investment.

Q. What specific mechanisms do you recommend be considered for MECO?

A. I recommend that the Commission convene a docket on PBR options, and let all parties come forward with alternatives. I believe that the goal should be to find options that link profitability to the level of total energy services cost to consumers, not to either utility sales volumes or utility investment. It would be well beyond the scope of this case to propose specific PBR mechanisms, but certainly within the scope to recognize that improving regulation requires a different approach than is currently in place.

A wide range of PBR options is included in Exhibit COM-204, the summary presentation from the course in PBR that I taught a few years ago in India.

ACTIONS THE PUC SHOULD TAKE IN THIS DOCKET

Q. What actions should the PUC take in this docket?

A. The Commission should set a goal to encourage high-efficiency distributed generation, and to defer or eliminate the need for construction of new utility-owned low-efficiency central generating units.

In order to do this, the Commission should do the following::

- Create a framework for distributed generation that rewards creativity and innovation.
- Restrict the utilities from entering into the DG business in their own service territories
- Require that the utilities provide standby power at reasonable costs
- Adopt rules that facilitate interconnection of customer-owned generation
- Implement connection charges for new customers and expanded loads that prevent existing customers from subsidizing load growth
- Direct the utilities to examine the creation of a virtual power plant from existing customer-owned emergency generators, and to report on the costs and benefits of doing so.

- Set a goal to avoid need for a new high-cost generating unit.

Q. Why should the PUC set a goal to avoid the need for new utility-owned generation?

A. It is clear that new utility-owned generation will increase rates for existing customers. If cost-effective alternatives are available, they should be pursued.

Q. What are the key elements to achieving this goal?

A. All of the recommendations I discuss in this section will help to avoid unnecessary development of high-cost power plants. Restricting the utility from exercising market power will help a competitive market for DG systems evolve. Establishing reasonable standby charges and reasonable equipment standards will facilitate development of DG as a resource. Connection charges for new customers will put customer-owned generation on a more level playing field with utility-supplied generation.

- Restrict the utilities from entering into the DG market as competitors.

Q. Why should the Commission restrict the utilities from entering the DG market as suppliers?

A. Quite simply, if the utilities can function as discriminating monopolists, offering lower-cost options to select customers, it will reduce their incentive to control costs that affect all other (captive) utility customers. The Commission should keep the utilities focused on their core mission, providing safe, reliable and economical service to all customers who request it on a nondiscriminatory basis.

The PUC should specify in this proceeding that a minimum 3-year moratorium will be enforced on any utility or utility affiliate from marketing DG equipment or service within the utility service territory.

- Require the establishment of reasonable standby charges for self-generators

Q. What type of standby charges should be put in place?

A. The Commission should order each utility to file a standby tariff that provides a low-cost source of backup service to customers with reliable DG systems. It should also provide that a customer that relies heavily on standby service will pay a higher total energy bill than a full-requirements customer, so that there is a strong incentive to choose reliable equipment and to maintain that equipment properly. This is done by having a low standby demand charge, and a relatively high standby energy charge designed to recover the majority of fixed costs in the event that "standby" service becomes more continuous in nature.

- Facilitate Interconnection of Customer-Owned Generation

Q. What steps should the PUC take to facilitate interconnection of customer-owned generation?:

A. The PUC should adopt reasonable equipment standards that provide for the reliability and safety of the utility system and of utility employees, but minimize the cost to on-site generation customers within those constraints.

The PUC should also direct each utility to identify areas in their service territory where transmission and/or distribution upgrades could be deferred if additional DG systems were developed, and to aggressively seek customers in these areas to choose DG systems, perhaps with targeted incentives in the form of capacity-deferral contractual payments.

Perhaps most important, the Commission should direct the utilities to provide information, education, and quality assurance programs to customers considering DG systems. This approach has worked very well in developing the market for solar water heaters, and I believe it can also work well for DG systems.

- Implement Generation Impact Fees for New Customers and Expanded Loads

Q. What type of impact fees should the Commission establish for new and expanding customer loads?

A. The ideal impact fee would be a full-cost charge, including the incremental cost of generation, transmission and distribution. The generation component alone would appear to equal or exceed $3,000 per kilowatt, based on current costs provided by MECO.

As a transitional step, adopting a "marginal minus average" approach for generation plant, similar to the way the current line extension policy applies to distribution plant, would help prevent the current problem where existing customers subsidize new customers, and new customers do not see the real cost of their required service when comparing DG and efficiency options to utility power supply.

I recommend that the Commission impose a $2,000 per kilowatt impact fee for all new and expanded loads initially, and refine this over a period of years for each utility.

- Direct the utilities to cooperate in development of a virtual power plant utilizing existing standby generators

Q. How should the Commission encourage the development of virtual power plants to take advantage of existing emergency generators to avoid higher utility costs?

A. The Commission should direct each utility to develop a plan to implement a virtual power plant in its service territory. This should include an inventory of possible generators, development of a plan to install synchronization equipment and central dispatch capability, and development of the contractual and institutional framework needed to make the program a success. Payments to the owners of this generation should be on a shared-savings basis, with the generator receiving a portion of the economic savings in the form of a reservation fee, and a portion in the form of a utilization fee when called upon to support the grid.

CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions and recommendations.

A. My testimony supports that presented by Mr. Kobayashi in presenting alternatives to encourage the development of distributed energy resources to provide cost-effective service to the citizens of Hawaii.

The primary ways in which it proposed to enhance these opportunities includes:

- A specific policy commitment by the PUC to support promotion of cost-effective distributed resources.
- Directing the utilities to provide standby service at reasonable rates
- Precluding the utilities from competing in the DG market, and require them to concentrate on their core missions to provide safe, reliable and efficient service to the public.
- Establishment of cost-based generation impact fees for new and expanded loads.
- Direct each utility to examine and evaluate the creation of a virtual power plant using existing emergency generators.

Q. Does this complete your prepared testimony?

A. Yes.