BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAI'I

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

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PUBLIC UTILITIES COMMISSION

THE DEPARTMENT OF BUSINESS, ECONOMIC DEVELOPMENT, AND TOURISM'S

PRELIMINARY STATEMENT OF POSITION

and

CERTIFICATE OF SERVICE

Filed ________________________, 2004

At ___________ o'clock _____.m.

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Chief Clerk of the Commission

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THE DEPARTMENT OF BUSINESS, ECONOMIC DEVELOPMENT, AND TOURISM'S

PRELIMINARY STATEMENT OF POSITION

The State of Hawaii Department of Business, Economic Development, and Tourism is participating without intervention in Docket 03-0371. As outlined in the motion to participate, the primary purpose for the Department's intervention is to carry out its Director's statutory responsibility, as State Energy Resources Coordinator (ERC), for formulating plans, objectives, criteria, for optimum development of energy resources and to conduct systematic analysis of existing and proposed energy resource programs of the electric utilities in Hawaii, as outlined in sections 196-3 and 4, Hawaii Revised Statutes (HRS). In particular, in this Docket, the Department is acting in support of section 196-4, (8) wherein the Department is charged with the duty to:

> Serve as <u>consultant</u> to the Governor, <u>public agencies</u> and private industry on matters <u>related to the acquisition, utilization and conservation of energy resources</u>;

1. The Department's Basic Position. The Department has consistently advocated increased use of distributed generation in the context of a regulatory structure that balances the interests of distributed generation owners/users, electric utilities, ratepayers, and providers of distributed generation systems.

The Department's advocacy of distributed generation is consistent with the State's statutory energy objectives as outlined in section 226-18, HRS, which state:

> (a) Planning for the State's facility systems with regard to energy shall be directed toward the achievement of the following objectives, giving due consideration to all:
>
> > (1) Dependable, efficient, and economical statewide energy systems capable of supporting the needs of the people;
> >
> > (2) Increased energy self-sufficiency where the ratio of indigenous to imported energy use is increased;
> >
> > (3) Greater energy security in the face of threats to Hawaii's energy supplies and systems; and
> >
> > (4) Reduction, avoidance, or sequestration of greenhouse gas emissions from energy supply and use.
>
> (b) To achieve the energy objectives, it shall be the policy of this State to ensure the provision of adequate, reasonably priced, and dependable energy services to accommodate demand.

DBEDT's encouragement of distributed generation stems from the inherent characteristics of typical DG systems. DG can increase the dependability or reliability of electricity service above that practical from the utility system alone. Many DG technologies, especially combined heat and power (CHP), offer greater fuel efficiency, better economics, enhanced energy security and reduced greenhouse gas emissions. Renewable DG systems can also increase energy self-sufficiency, contribute more to energy security, and reduce greenhouse gas emissions, making them especially desirable from the State's perspective.

The U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy Distributed Energy Program states that DG "has the potential to produce benefits on both sides of the electric meter.[1]"

Consumer-Side Benefits

- Better power reliability and quality
- Lower energy costs
- More choice in energy supply options
- Greater predictability of energy costs (lower financial risk) with renewable energy systems
- Energy and load management
- Combined heat and power capabilities
- Environmental benefits—including cleaner, quieter operation, and reduced emissions
- Faster response to new power demands—as capacity additions can be made more quickly

Grid-Side Benefits

- Reduced energy losses in transmission lines
- Reduced upstream congestion on transmission lines
- Reduced or deferred infrastructure (line and substation) upgrades
- Optimal utilization of existing grid assets—including potential to free up transmission assets for increased wheeling capacity

[1] See "The DE Solution" at http://www.eere.energy.gov/de/basics/der_basics_dersol_bene.shtml

- Less capital tied up in unproductive assets—as the modular nature of distributed generators means capacity additions and reductions can be made in small increments, closely matched with demand, instead of constructing central power plants sized to meet estimated future (rather than current) demand

- Improved grid reliability

- Higher energy conversion efficiencies than central generation

- Faster permitting than transmission line upgrades

- Ancillary benefits—including voltage support and stability, contingency reserves, and black start capability

DBEDT's position paper is intended to offer ideas and resources on the issues in this docket for consideration by the parties that reflect the State's energy objectives.

In addition, DBEDT has provided a compilation of Distributed Energy Information Sources for the parties' information as Appendix 1 to this document.

Discussion of the Issues

1. What must be considered to allow a distributed generating facility to interconnect with the electric utility's grid?

The Department of Energy, DBEDT and the Interstate Renewable Energy Council sponsored a Workshop on Interconnecting Distributed Energy, held on December 12 and 13, 2002, in Honolulu, which described and discussed interconnection of DG systems. Tom Starrs, of Kelso Starrs & Associates presented an *Overview of Interconnection Issues*. He noted that, "integrating customer-owned, customer-sited DG facilities into the utility grid depends on the ability of consumers to purchase, install, and interconnect this equipment easily." He cited three sets of issues that needed to be addressed, which we have reordered to conform with our discussion, below. The issues are:

1. Technical requirements for interconnection to deal with safety and power quality issues;
2. Non-technical requirements for interconnection, such as legal, procedural, and economic issues; and
3. Metering arrangements, which determine energy value;

HECO Interconnection Standards (Technical Requirements) and Standard Interconnection Agreement (Non-Technical Requirements)

At the Workshop, Tom Simmons, then Manager of HECO's Power Supply Services Department, made a detailed presentation on Interconnection Procedures for the HECO system. He also announced that HECO had draft interconnection standards and a standard interconnection agreement. Ultimately these became effective March 21, 2003 by Public Utilities Commission (PUC) Decision and Order (D&O) No. 20056, filed March 6, 2003. By D&O No. 20220, filed May 30, 2003, the PUC approved a modification to the insurance provision of the standard interconnection agreement, which became effective June 6, 2003.

DBEDT does not have the resources to do a detailed analysis of the interconnection standards and standard interconnection agreement, and defers to DG owners and vendors as to whether there may be a need to change or update the HECO interconnection agreement.

DBEDT notes that since the HECO standards and agreement were approved, the Institute of Electrical and Electronics Engineers, Inc (IEEE), has issued a standard for interconnection of DG systems. Four HECO staff members participated in the 1547 Working Group that developed the IEEE 1547 Standard and the work in progress at the time that HECO developed its standards and agreement may have been included.

IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems[2] was approved by the IEEE Standards Board in June 2003. It was approved as an American National Standard in October 2003. Additional related standards under development include:

- IEEE P1547.1 Draft Standard for Conformance Tests Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems[3];
- IEEE P1547.2 Draft Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems[4];
- IEEE P1547.3 Draft Guide For Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems[5]; and
- IEEE P1547.4 Draft Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems.[6]

Interconnection for Smaller Systems

Cost is an important consideration in deciding whether or not to deploy DG. Smaller systems may not need as sophisticated or costly DG interconnection to effectively protect the utility system and to protect the DG device. Accordingly, the National Association of Regulatory Utility Commissioners (NARUC) has developed *Model Interconnection Procedures and Agreement for Small Distributed Generation Resources*. Hawaii could benefit by

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2 Available at http://grouper.ieee.org/groups/scc21/1547/1547_index.html

3 Available at http://grouper.ieee.org/groups/scc21/1547.1/1547.1_index.html

4 Available at http://grouper.ieee.org/groups/scc21/1547.2/1547.2_index.html

5 Available at: http://grouper.ieee.org/groups/scc21/1547.3/1547.3_index.html

6 Available at http://grouper.ieee.org/groups/scc21/1547.4/1547.4_index.html

consideration of NARUC's recommendations when considering modifications to the utilities' current interconnection standards and agreement.

Net Metered Renewable Energy DG Technical and Non-Technical Interconnection Process

Currently, net metered renewable energy DG interconnection, which is less than 10 kW is very simple. The customer-generator and electrical contractor simply complete a Net Energy Metering Agreement[7] on which they certify that

> Generating and interconnection systems must be compliant with all applicable safety and performance standards of the National Electrical Code (NEC), Institute of Electrical and Electronic Engineers (IEEE), and accredited testing laboratories such as the Underwriters Laboratories (UL), and where applicable, the rules of the Public Utilities Commission of the State of Hawaii, or other applicable governmental laws and regulations, and the Company's interconnection requirements, in effect at the time of signing this agreement.

Specifications for installation on the Net Energy Metering Agreement are stated on the form.

DBEDT suggests similar simplified interconnection agreement procedures be considered for non-renewable and renewable systems to some greater threshold than the current 10 kW.

Metering Arrangements for Renewable DG

Part VI, Chapter 269, Hawaii Revised Statutes, provides for net metering of renewable energy systems. The law specifies "solar, wind turbine, biomass, or hydroelectric energy generating facility, or a hybrid system consisting of two or

[7] HECO's Net Metering Agreement is available at http://www.heco.com/images/pdf/NEM_agreement.pdf

more of these facilities, with a capacity of not more than ten kilowatts" as eligible, when meeting additional requirements of the statute.

Net metering is defined as "measuring the difference between the electricity supplied through the electric grid and the electricity generated by an eligible customer-generator and fed back to the electric grid over a monthly billing period." These terms provide full value to net metered electricity, and should seemingly serve to encourage additional renewable energy. However, few net metered systems have been deployed.

DBEDT postulates that the 10 kW limit may be an obstacle. While few residences need a system so large, few homeowners are installing net metered systems. At the same time, the 10 kW limit may be too low for many businesses, which would enjoy additional federal tax credits. A 100 kW limit was proposed in Legislation in 2003[8] and a 50 kW limit was considered in 2004[9]. California allows for net metered systems up to 1 MW.

2. Who should own and operate distributed generation projects?

Given the potential advantages of DG to electric utility customers/end users, Hawaii's electric utility systems, and society as a whole, DBEDT believes that electric utility customers/end users, energy service companies/DG vendors, and the electric utilities should be allowed to own and operate DG projects. DBEDT supports a level playing field when it comes to DG ownership and operations relative to the utilities, which could also complement their marketing of energy efficiency measures.

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[8] SB 1682 and HB 1676

[9] HB 2048, HSCR 618, and SSCR 3276

3. What impacts, if any, will distributed generation have on Hawaii's electric transmission and distribution systems and market?

The positive impacts on Hawaii's electric transmission and distribution systems can be significant if deployments of DG are targeted to areas where there are existing or potential constraints, or need for redundant lines for reliability. Examples include MECO's use of DG to avoid the need to build additional transmission to Hana, HELCO's use of DG to improve power quality and, in the future, to potentially help meet demand growth in West Hawaii. In addition DG may help MECO meet possible needs for greater reliability in West Maui. It appears that such deployments could be particularly appropriate for utility DG/CHP programs. In addition, incentives and requests for proposals could be offered for non-utility DG/CHP in targeted areas.

DG should also be used instead of transmission and distribution system additions or upgrades for businesses or organizations requiring greater reliability than the utility system offers. It is not equitable to expect all ratepayers to pay for level of power quality needed only by a few, if such a level of power quality is attainable at all on a utility system scale.

4. What is the role of the regulated electric utility companies and the Commission in the deployment of distributed generation in Hawaii?

DBEDT supports the concept of regulated utility sales of CHP services to utility customers. DBEDT offers some resources for the consideration of the parties that offer ideas on this issue.

In his paper, *Distributed Generation - A Fair and Simple Plan for Utilities and Policy-Makers*[10], R.S. Brent of Solar Turbines Incorporated suggests that "distributed generation faces institutional barriers erected in the era before distributed generation technology emerged as an economic alternative", including "existing rate and regulatory regimes that fail to offer appropriate incentives to utilities and customers who would substitute distributed generation facilities for distribution and generation."

Mr. Brent recommends changes to enable DG to compete economically with traditional central station generation. He focuses on methods that provide incentives to customers and utilities to install cost-effective distributed generation facilities. These were summarized as follows:

> The primary recommendation of this paper is that distribution utilities be required to engage in a "localized" least cost planning process for their distribution facilities. This process would be analogous to generation least cost planning, to establish zones in which installation of distributed generation facilities would be encouraged through the provision of credits that recognize the benefits provided to the distribution system by the distributed generation facilities. These credits should be available to any customer that installs distributed generation facilities in a distributed generation zone. A utility should be allowed to install distributed generation facilities in a distributed generation zone and should be entitled to recover in its distribution rates the capital and operating costs of the distributed generation facility, subject to crediting of the generation-related revenues from the distributed generation facility.

10 Available at http://uschpa.admgt.com/SolarT-DGforUtilsPolicyMkrs2002.pdf

It is reasonable to expect the utilities will provide equitable treatment of customer/ESCO interconnection applications, and equally reasonable for the Commission to be prepared to resolve any differences that may emerge.

5. **What is the appropriate rate design and cost allocation issues that must be considered with the deployment of distributed generation facilities?**

Rate Design

The authors of *Small Is Profitable*[11] state that DG poses four primary threats to the existing vertically integrated business model. First, DG results in the loss of revenue, because the customer purchases fewer kWh or fewer distribution services. Second, more substantial market capture by DG can result in stranded grid capacity no longer needed. Third, the ability to deploy DG more rapidly than centralized generation or transmission upgrades can partially strand new capacity additions. Fourth, the combination of the first three threats can create a "death spiral" in which the higher prices to remaining customers induce more of them to leave this system, creating a self-reinforcing cycle of ever-increasing unit prices.

Their recommendations for states with traditional utility regulation are:

1. <u>Decouple utility revenue requirements from kWh sold, and create incentives to lower customers' bills, not price per kWh</u>. This decoupling of revenues from sales, through revenue caps or balancing accounts, fundamentally changes the

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[11] *Small is Profitable.* Rocky Mountain Institute, 2003, available for purchase at: http://www.smallisprofitable.org/

incentives and hence the culture of regulated utilities. Regulated utilities should be rewarded not for selling more kWh, but for helping customers get desired end-use services at least cost. Utility shareholders should share in the savings if overall revenue requirements are reduced. This can be done by a performance-based approach to providing utility incentives.

2. Require mandatory ERIS [IRP] planning as the basis for prudent cost recovery. With revenues decoupled from sales, a regulated utility has the incentive to identify and implement the least-cost options to serve incremental demand growth. The inclusion of distributed generation and targeted DSM can help reduce system costs by significantly expanding the menu of available resources that must compete with each other, including:

   - small-scale DG *facilities* located near the source of load growth,
   - *differentiated tariffs* to encourage customers to limit demand during peak hours,
   - targeted *energy efficiency and load management* for customers or uses that drive the peak demand, and
   - central-grid power, incurring the *cost of new T&D capacity* to transport the power to customers with new and/or increasing loads.

3. Restructure distribution tariffs to reduce excessive fixed charges. The authors recommend that the distribution [portion of the] tariff structure be progressively shifted toward a greater proportion of volumetric pricing (usage-based unit prices) rather than fixed pricing. The unit prices would aim to approach the long-run marginal costs of the system in order to send correct price signals and promote economic efficiency.

4. Adopt renewable portfolio standards (RPS) and tradable credits. States that continue with traditional regulation need some form of RPS in order to provide a systematic hedge on fossil-fuel prices and to enhance energy security.

Cost Allocation for DG

DBEDT staff attended the January 2004 Meeting of the California Alliance for Distributed Energy Resources (CADER) Conference[12] in San Diego. A presentation by Ms. Ellen Petrill, of the Electricity Innovation Institute (E2I), on *DER Costs and Benefits: Finding Win-Win-Win Approaches* offered a number of ideas regarding utility deployment of DG that we offer for the parties' consideration. The presentation was based on work in progress sponsored by the Electricity Innovation Institute (E2I) and its partners: the California Energy Commission, New York State Energy Research and Development Authority, and the Tennessee Valley Authority. The DRAFT report entitled, *A Framework For Developing Collaborative DER Programs: Working Tools for Stakeholders*, and is provided as Appendix 2 to this Position Statement.

The following attempts to summarize and paraphrase key points of the report:

> The inability of today's electricity markets to recognize and account for these benefits where they exist alone or in combination, has led E2I and a group of interested stakeholders to reexamine the processes for integrating DER into those markets. The goals of this collaborative effort are to:
>
> - understand DER costs and benefits from various stakeholder perspectives
> - create incentives that accurately reflect and fairly allocate these costs and benefits
> - facilitate pilot programs that can show how to reduce DER costs and monetize benefits, and how to better integrate DER into prevailing electricity markets.

[12] See the CADER web site at http://www.cader.org/ for access to presentations and papers.

Chapter 1 catalogs approaches and incentives that states and utilities are already taking to facilitate DER and related demand response that add value for electric systems and their customers. The current approaches are organized by primary interests of the distribution utility and the bulk power utility [a single vertically integrated utility such as in Hawaii], the DER customer, and society at large.

The report posits that the *distribution utility* [or distribution element of a vertically integrated utility] seeks to enhance distribution system reliability through cost-effective asset deployment. Regulators and utilities have tried various approaches to DER in pursuit of these objectives, including:

1. requiring utilities to evaluate DER as an alternative to system upgrades, and to develop or procure DER solutions where they represent least-cost or best-fit solutions;
2. targeting incentives to reflect the value that DER can bring to specific local areas or circuits on the utility grid;
3. using customer-sited equipment to improve grid reliability; and
4. rewarding customers for scheduling their loads to support grid operations.

The *bulk power utility's* [or power production and transmission elements of a vertically integrated utility] focus for DER is likely to be mitigating wholesale prices [or generation costs in the case of a monopoly vertically integrated utility] and/or relieving transmission congestion by some of the following actions, including:

1. facilitating or installing DER that can be dispatched to relieve pressure on locational marginal costs, or to reduce peak transmission costs as an alternative to firm peaking capability;
2. purchasing DER from third-party aggregators who contract directly with customers to assemble supply

and demand resources responsive to utility needs [aggregation could also be carried out by vertically integrated utilities]; and

3. paying customers to curtail their loads at critical times, and dispatching aggregated load control as a system resource.

The *DER customers* usually seek to increase reliability and reduce energy costs through DE/CHP, and/or to expand the energy and financial options. These objectives result in approaches such as:

1. value-added time-of-use pricing services that enable customers to schedule their usage to reduce their bills;
2. installation and operation of onsite cogeneration systems with guaranteed savings for the host facility; and
3. adoption of onsite generation that increases site reliability and reduces net energy costs by taking advantage of hourly pricing options to profit from sales into wholesale markets.

Finally, the *regulatory and societal* focus for DER is to increase the efficiency of energy production, delivery and use and improve environmental quality. These have been encouraged by the following:

1. customer rebates and equipment buy downs for renewable, 'ultra-clean' or highly efficient DER, and/or CHP projects meeting specified criteria; and
2. portfolio standards that require utilities and other load-serving entities to acquire some minimum percentage of diversified renewable resources, including distributed renewables.

Chapter 1 presents specific examples where each of these approaches has been used, describes the programs that have used them and the nature of any incentives employed, and highlights the features that distinguish each example from other similar programs.

Chapter 2 examines costs and benefits of DER, and how utility rate structures and incentive approaches affect their allocation among key stakeholders for purposes of achieving 'win-win-win' outcomes. These include use of the following:

- Ratepayer Impact Measure;
- Participant Cost Test;
- Total Resource Cost Test; and
- Societal Cost Test.

All perspectives are considered to find solutions that can be cost-effective or 'winners' for multiple stakeholders, and to aid in program design.

Specific types of costs and benefits, both direct and indirect, can be identified for each stakeholder group. For example, costs and benefits to the DER customer would include:

	Benefits	Costs
Direct	Annual electricity bill savings Annual avoided fuel costs (thermal) Wholesale energy sales Renewable energy credits (sales of)	Annual capital costs; DER maintenance; DER fuel costs (including siting and permitting if customer-owned project) Emissions offset purchases Interconnection study, equipment, & electric system upgrade costs Insurance Other utility infrastructure & operational costs
Indirect	Customer reliability	

Chapter 2 presents similar benefit/cost tables from the perspectives of other stakeholders (the utility, society, etc.), followed by more detailed descriptions of each cost and benefit category.

Once a qualitative set of costs and benefits is identified from each stakeholder's perspective, the next steps are to quantify them, and to determine whether various combinations of them can yield net benefits that might be re-allocated among the stakeholders to achieve outcomes that benefit all or most of them, without harming others.

The E2I team has developed an **Excel spreadsheet model** that illustrates an analytical approach that can be adapted to all of these situations. To keep this version of the model manageable and affordable, it focuses on California and its three major investor-owned utilities. The spreadsheet uses actual rate structures and tariffs, and actual regulatory incentives in place in California in 2003. Other inputs, such as generation and T&D avoided costs, interconnection costs, generation multiplier, and emissions control costs can be entered. [DBEDT believes the model could be revised to reflect and used as an analytic tool to examine Hawaii's situation.]

The model structure enables users to vary numerous inputs relevant to DER projects to see how they affect the costs and benefits flowing to each of the stakeholder groups identified above. Its output reveals which stakeholders profit and which ones pay for different combinations of DER technologies under differing assumptions.

Where model results show substantial net benefits for one stakeholder group and net costs for another under relevant cost-effectiveness tests, it suggests the possibility that re-allocating some of the costs and benefits generated in that scenario could result in net benefits to all parties and net costs to none (or lower costs to some). In doing so, it identifies scenarios that may be subject to constructive collaboration among stakeholders to achieve benefits for all of them - considering that scenarios that benefit one stakeholder group at the expense of others often face opposition resulting in project failures that benefit no one.

Chapter 3 focuses on methods available to allocate DER costs and benefits among stakeholders. For regulators and policymakers, utility revenue setting and rate design are the critical points where DER intersects with the utilities they regulate. The rates that end-users pay for grid-supplied electricity largely drive DER economics, and the ways that utilities are compensated for supplying that electricity can determine their receptivity to DER development. This means that utility revenue setting and rate design offer important tools to shape DER incentives, and thus help or hinder DER integration into emerging electricity markets.

While the prospect of reducing their bill from the utility can induce customers to pursue DER, the other side for the utility is that any bill reductions the customer achieves can reduce utility earnings, if revenue reductions are not offset by equivalent cost savings to the utility. One objective of rate design is to ensure that rates present price signals to customers that mimic the costs utilities actually incur or avoid. Designing efficient rates and appropriate utility pricing structures therefore requires an understanding of how utilities incur costs, which of these costs DER can actually affect, and under what circumstances it can affect them.

DER can reduce costs for a *subset* of the total costs that a utility must recover from its customers. However, utility rates are designed to recover the *total* costs plus a reasonable return on utility investment. This means that customer bill reductions from DER that are not tied to the subset of costs actually reduced can exceed the true savings available to the utility. Because mismatches can occur between customer bill reductions and utility cost savings, utilities are sometimes averse or at least disinclined to promote DER. To minimize this source of disincentives, it is important that regulators set policies and design rates that align customer bill savings with utility cost savings, so that utility and customer interests move in the same direction.

Basic rate forms that can make it easier or harder to align these interests include volumetric (energy) charges, fixed charges, and demand charges. Rate designs with high fixed and/or demand charges help ensure utility cost recovery independent of customer energy usage, so they minimize utility financial incentives to oppose DER. On the other hand, these rate forms provide weak price signals or none at all that would induce customers to adopt DER that could benefit the system, the environment or other ratepayers, and they make it difficult or impossible for customers to capture economic benefits from DER, limiting DER deployment to 'super' cost-effective resources.

The argument for large fixed-cost rate components rests on the idea that many utility costs do not vary much in the short run, and that short-run marginal delivery costs are often very low, sometimes approaching zero. However, many of those same costs can vary in the long run, and it is important to recognize this in setting fixed charges.

Two such methods discussed in the report include 'demand subscription' and non-firm standby options. Both offer alternatives to conventional standby charges that often discourage DER development. Standby rates typically assume that the utility retains its obligation to supply the customer's load when the customer's onsite generation is down for maintenance or unscheduled outages. Demand subscription and non-firm rates instead assume that customers should be able to chose the level of standby they need for their operations. For DER customers that do not require firm service or value it highly, demand subscription offers a way to pay only for the capacity they do need and value, accepting some level of risk in return for reduced costs. For small DER customers whose back-up requirements would not drive T&D peaks in any case, non-firm service offers a way to secure back-up service for most times of the year, except possibly during periods of utility peak demand. Both alternatives to conventional standby rates also expand DER customer choices, without imposing the costs of these choices on other stakeholders.

A third method that can help align utility and DER customer interests is a 'two-part' rate form that protects utility revenues while providing price signals to customers to help control utility costs. This rate form collects the customer's historical billing, but it also charges for increased usage (or credits reduced usage) at the utility's marginal cost - i.e., the cost of expanded facilities avoided or deferred through customer DER initiatives.

If DER benefits are large enough, these rate innovations can help customer-side DER into the marketplace without prejudicing utility shareholders or non-participating customers. However, the modeling tool described above suggests that DER may require more leverage to significantly penetrate electricity markets. One way to obtain that leverage is to explicitly recognize additional DER values where they exist.

This can be done in various ways. California now requires utilities to consider DER as an alternative to distribution upgrades, and to take steps to procure it where it appears to offer a least-cost solution. New York requires its utilities to evaluate DER for T&D projects whose costs exceed certain benchmarks, and oversees a pilot program that requires utility RFPs to procure DER where it can defer T&D capacity needs. Costs that utilities incur for prudent DER procurement, including the costs of any incentives needed to direct DER to high-value areas, can be funded from utility transmission or distribution budgets, and capitalized like traditional plant investments to protect utility shareholders.

Another way to capture additional values offered by some DER is to monetize the societal costs of emissions. In that case, benefits accruing from clean DER technologies could be paid for out of 'public goods' or 'system benefit' surcharges levied on all utility sales in some jurisdictions [but not Hawaii]. Utility shareholders are not harmed because such funds are already earmarked for public interest programs and funded through a dedicated rate component, and utility earnings are unaffected.

DBEDT suggests that the parties may benefit by considering the technical substance, and process approaches offered in Ms. Petrill's draft report. This information could be useful in addressing many of the docket's issues.

Customer Retention Rates

DBEDT believes that, if utilities can provide customers with DG, existing customer retention rates no longer appear relevant.

Standby Charges

DBEDT is concerned that excessive, inflexible, or inappropriate standby charges may discourage deployment of DG. DBEDT recommends re-evaluation of Hawaii's existing standby charges and consideration of the policies described in California Public Utilities Commission's (CPUC) Decision 01-07-27 *Interim Decision Adopting Standby Rate Design Policies*[13] , (See Section 7. Discussion and Summary of Adopted Standby Rate Design Framework[14] and Conclusions of Law[15]).

In Section 7, the CPUC defined the major issues in standby

[13] Available at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/8823-06.htm#P266_103971
[14] Section 7 at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/P273_105965#P273_105965
[15] Conclusions of Law at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/8823-10.htm#TopOfPage

rate design as follows: "the nature of the costs to serve standby customers; different types of standby service; whether costs of standby service should be recovered through fixed or usage-based rates; how to reflect diversity in rates; interruptible rates; credits for reliability; and other optional rate designs such as area and/or time-specific rates." CPUC also had a goal of consistency in the design of standby rates for all California utilities. They also noted, "Because the standby rates design policies we adopt herein are cost-based, and there is no evidence that distributed generation deployment will soon cause significant stranded distribution costs, implementation of these policies will not harm the utilities."

The following were the "Conclusions of Law" that DBEDT believes would be relevant in developing new standby rates in Hawaii:

1. Rate design and ratemaking policies should:

   a) provide for fair cost allocation among customers;

   b) allow the utility adequate cost recovery while minimizing costs to customers;

   c) accommodate customer-side distributed generation deployment; and

   d) send proper price signals to prospective purchasers of distributed generation.

2. Customers should be able to enter into a contract to specify the capacity for which it will provide physical assurance [DBEDT comment: that customer(s) will not need standby service for that amount of capacity].

3. Customers with onsite generation should not pay standby charges designed to recover the fixed costs associated with distribution service for the amount of capacity it provides to the utility with physical assurance.

4. It is appropriate for distribution infrastructure costs to be recovered from backup customers.

5. Supplemental power should continue to be priced according to the customer's otherwise applicable tariff.

6. Standby rates should appropriately reflect the reduced cost of providing services such as backup and maintenance service compared to supplemental service.

7. In order to recognize the cost difference between supplemental power and backup power needs, we should require the utilities to reflect diversity, where it actually exists, in the standby reservation charges.

8. Backup service should be allocated a greater share of costs than maintenance service because it is an on-demand service and has distribution infrastructure requirements associated with it.

9. Diversity factors should not be applied to distribution charges that recover fixed costs at this time.

10. The utilities should be required to separately calculate diversity factors for the transmission and distribution level interconnected generation as a result of this decision.

11. If costs associated with maintaining distribution and transmission facilities to serve diversified standby load are fixed, those costs are appropriately reflected in fixed reservation or demand charges.

12. To the extent that there are costs that do vary with usage, those costs should be reflected in a usage-based charge.

13. Standby customers with onsite generation who sign up for backup service should be charged a $/kW reservation charge for their reserved capacity.

14. The reservation charge should reflect the facilities-related distribution infrastructure costs that do not vary with usage.

15. Backup standby rates should include a volumetric rate, based on actual usage, that collects variable

distribution costs, including peak demand-related costs.

16. Maintenance customers and others whose use of the distribution system is on an as-available basis should be charged a volumetric rate, based on usage, that recovers variable distribution costs but does not include peak demand-related infrastructure costs.

17. Standby charges should be based on embedded, not incremental, costs of service, consistent with the manner in which rates are calculated for other distribution services.

18. Standby rates should remove any charges not associated with providing distribution standby service.

[The remaining points were not applicable to Hawaii's utility system.]

6. What revisions should be made to the integrated resource planning process?

We note that the HECO utilities are planning for forecasted combined heat and power for the first time in IRP-3. We believe that this should be continued. As noted above in the discussion of Issue 4, R.S. Brent suggested an approach that could be considered:

> the utility should be required to engage in a localized least cost planning exercise, in which it compares the costs and benefits of the distributed generation unit(s) to the sum of all of the avoided costs and benefits it would receive from reduced investment and operating costs in distribution, central station generation, and purchased power and transmission. At the conclusion of the localized least cost planning procedures, the utility should choose the lowest cost option.

7. What are the impacts of distributed generation on power quality and reliability?

Generally, DG can enhance power quality and reliability for users. As noted in our discussion of Issue 3, DG should be used instead of transmission and distribution system additions or upgrades for businesses or organizations requiring greater reliability than the utility system offers.

The utility can also benefit from improved power quality and reliability provided by DG as demonstrated by both MECO and HELCO in recent years. Please see the discussion of Issue 3.

8. **What forms of distributed generation (e.g., renewable energy facilities, hybrid renewable energy systems, generation, cogeneration) are feasible and viable for Hawaii?**

DBEDT believes that all commercially available forms of distributed generation, renewable energy systems, conventional fuels, and hybrid systems, are feasible in Hawaii. Fossil fueled DG/CHP that would use natural gas on the Mainland would need to use synthetic natural gas, LPG, naphtha, or diesel in Hawaii.

9. **What is the potential for distributed generation to reduce the use of fossil fuels?**

Generally, renewable DG will reduce fossil fuel use by 100% of fossil fuel previously used to produce the electricity now produced by the renewable DG. Customer sited DG without heat recovery may have efficiency comparable to the utility system, but will avoid line losses.

10. **What utility costs can be avoided by distributed generation?**

Very generally, some transmission and distribution costs and fuel costs can be avoided. More detail on additional considerations are provided in the response to Issue no. 5.

11. What are the externalities costs and benefits of distributed generation?

In general, DBEDT believes that the efficiencies of DG, and especially CHP and renewable DG relative to fossil fuel central station generation create benefits that outweigh the costs.

12. The parties and participants can also address issues raised in the informal complaint filed by Pacific Machinery, Inc., Johnson Controls, Inc. and Noresco, Inc. against HECO, MECO and HELCO on July 2, 2003.

DBEDT encourages the parties filing the complaint and the utilities to arrive at a resolution of the issues. DBEDT offers to assist in developing a solution consistent with State energy policy and the interests of all stakeholders, through our participation in this docket.

DATED: Honolulu, Hawaii, May 7, 2004.

MAURICE H. KAYA, P.E.
Chief Technology Officer
Department of Business, Economic
Development, and Tourism
STATE OF HAWAII

By ______________________
MAURICE H. KAYA
Chief Technology Officer

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