8-18-04

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

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

RESPONSE OF HAWAII RENEWABLE ENERGY ALLIANCE

TO

INFORMATION REQUESTS FROM VARIOUS PARTIES

ON

HREA'S T-1 (WARREN S. BOLLMEIER II) DIRECT TESTIMONY

AND

CERTIFICATE OF SERVICE

Warren S. Bollmeier II, President
HREA
46-040 Konane Place #3816
Kaneohe HI 96744

(808) 247-7753

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

The Hawaii Renewable Energy Alliance (HREA) hereby submits our response to Information Requests (IRs) from various Parties on our T-1 Direct Testimony (Warren S. Bollmeier II), dated and submitted to the Public Utilities Commission (PUC) on July 28, 2004 in accordance with the PUC's Prehearing Order Number 20922 (Reference Docket No. 03-0371).

I. <u>INTRODUCTION</u>

HREA received IRs from the following Parties: A. the County of Maui (see pages 3 to 6), B. HECO (see pages 7 to 10), C. Hess-Microgen (see page 11), and D. Kauai Island Utility Cooperative (see pages 12 to 14). HREA's response, prepared by its President (Warren S. Bollmeier II), is included in Section II.

Please note that the IR format, including numbering system, is as received from the individual Parties. Also note that HREA's response to the Parties includes references to WSB-Hawaii's study, entitled "Study of Renewables and Unconventional Energy in Hawaii, which was prepared for the Hawaii Energy Policy Forum. The study can be reviewed and/or downloaded at the following web-site location: http://hawaiienergypolicy.hawaii.edu/papers/bollmeier.pdf.

II. RESPONSE TO INFORMATION REQUESTS FROM THE VARIOUS PARTIES

A. THE COUNTY OF MAUI

COM-HREA-DT-IR-78

HREA page 12: What information do you propose that the utility would provide to potential DG providers, including a utility unregulated affiliate, regarding customer consumption and characteristics? Should the customer's permission be required for the release of this information?

HREA Response: In HREA's proposed structured competition model, the utility would provide the desired areas and types of DG technologies on their grid, and, where possible, specific information regarding potential DG customers to potential DG providers, as part of the utility's facilitation of DG on its DSM and SSM programs. This specific information, including peak demand, energy use, and daily/seasonal variations, would come from the utility's analysis conducted in their IRPs, utility knowledge of specific customers, and utility requests potential DG customers for information from and interest utility-sponsored DG projects.

IRP Analysis. The DG working committees of the utility IRPs would identify the desired types of DG technology and key areas on each of our island grids. In the near term, HREA believes there may be an emphasis on CHP and other DG technologies that can provide firm power as defined by the utility (fossil generation, fossil CHP, and biomass co-generation). Coincidentally, HREA believes the utility should also be looking harder at intermittent renewable sources, not just for RPS, but also for their ability to provide capacity when needed.

Given that the utility is also conducting detailed analyses of their transmission and distribution needs, HREA believes it is possible for the utility to identify locations on their grid where DG would be most beneficial. Some of these might appear to be obvious, such as downtown Honolulu and Waikiki, while others may not.

Customer Information. HREA believes the utility has direct knowledge of customer loads, including overall demand and energy usage, as well as a load profile in some, if not many, cases. In any case, given the IRP analysis results, HREA proposes that the utility solicit interest from potential DG customers. In this solicitation, potential DG customers would be required to authorize release load usage data and information. In return, the potential DG customers would be guaranteed inclusion as candidates in a follow-on utility solicitation for DG projects. Furthermore, with the release of the follow-on solicitation, the participating customer would likely receive multiple bids for projects to meeting their energy needs, as well as meeting the utility's DG requirements. Individual DG customers could, of course, decline to provide load usage data and information up-front, but still participate later in the DG project solicitation.

COM-HREA-DT-IR-79

EXHIBIT HREA-A: The witness has consulted with several wind energy projects. Provide any studies received or prepared by the witness addressing the capacity value of wind energy projects.

HREA Response: In the referenced WSB-Hawaii's study for the Hawaii Energy Policy Forum study, Mr. Warren S. Bollmeier II identified a near-term (2003 to 2008) potential capacity of 110 MW for five windfarm projects as follows: Oahu (50 MW at Kahuku), Maui (20 MW at Kaheawa Pastures), Hawaii (10 MW at Hawi and 20 MW at South Point). At the present time, Mr. Bollmeier has not prepared a detailed study of the capacity values of these wind projects. However, Mr. Bollmeier believes that average capacity factor (average power output of a windfarm over time divided by its rated capacity) should be the basis for establishing a capacity value. For example, a properly-sited and designed windfarm in Hawaii should have a capacity factor ranging from 30% to 40% or more. Mr. Bollmeier suggests that the capacity value should be at least one-half of the actual capacity factor, or in the examples just given, 15% to 20% or more.

Precedents. There is precedent for establishing an applying capacity values in other jurisdictions, e.g., in California. Capacity payments were made to windfarms on standard offer contracts that were applicable in the 1980's and early 1990's. The effective capacity value for wind under the Standard Offer 1 (SO1) Contract offered by Southern California Edison (SCE) was 0.15 for wind on the initial SO1s awarded in the early 1980's. Note: the energy payment is based on short run avoided costs (SRAC), and HREA understands that capacity credits will be available for intermittent sources on California's new Renewable Portfolio Standard (RPS).

Currently, the California Public Utility Commission is investigating capacity values for intermittent sources in support of California's RPS. The relevant rulemaking order (No. R. 04-04-026) can be downloaded from the California Public Utility Commission web site.[1] From page 7 of the rulemaking order (emphasis added):

> "5. Least-Cost/Best-Fit
>
> Least cost and best fit is the shorthand term established by the RPS legislation to describe the process of bid ranking the utility is to undertake in the RPS program. D.03-06-071 developed the majority of the components of this evaluation, and identified two components for further work. Those two components are **establishing capacity values for intermittent technologies** and developing bid adders to reflect the cost of transmission needed to connect new renewable generation to the grid.
>
> **On the issue of capacity values for intermittent technologies**, the Commission directed that the RPS program utilize either the standard approach employed for Qualifying Facility (QF) resources, or, should the results become available in time, the more refined analysis contained in the report, "California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis" (CEC Study) prepared by the California Wind Energy Collaborative under the auspices of the CEC's Public Interest Energy Research Program."

[1] Reference: http://www.cpuc.ca.gov/static/industry/electric/renewableenergy/index.htm).

An RPS integration study[2] is under way on behalf of the CEC, which provides analysis of capacity values for intermittent resources as an alternative to the SO1 approach. Based on an analysis of existing windfarms, the capacity credit values for the windfarms ranged from 22% (Tehachapi area) to 23.9% (San Gorgonio area) to 26% (Altamont area). For more details, see the executive summary of the Phase I Cost Analysis in Exhibit A.

Hawaii Analysis. HREA is not aware of a study in Hawaii similar to that underway in California. However, there is one relevant study that did address capacity value for a proposed windfarm on the Big Island. The study resulted from Apollo Energy Corporation's petition to the PUC (reference Docket No. 00-0135), which included the issue of capacity value and credits for Apollo's proposed re-power of their Kama'oa Windfarm at South Point to 20 MW. Specifically, Apollo had requested capacity payments from HELCO as part of the power purchase agreement (PPA). HELCO had refused to make the capacity payments, and Apollo subsequently petitioned the PUC for relief on that and other PPA issues.

In rebuttal testimony that followed a hearing before the PUC in October 2000, Carl Friedman (Haiku Design and Analysis) discussed a technical support and analysis study that he had prepared on behalf of Apollo. This study focused on the capacity value of as-available (intermittent) resources to HELCO. On page 3 of his 27 page testimony[3], Mr. Freedman indicated the following overall findings:

(1) "Intermittent resources contribute to the reliability of HELCO's system,

(2) Intermittent resources such as Apollo's wind farm have the ability to defer HELCO firm generation additions and avoid firm capacity costs."

However, Mr. Freedman did not establish or recommend any specific capacity values or credits. Note: a copy of the 27-page document will be attached to the email copy of this document to all the Parties.

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[2] "California RPS Integration Cost Analysis-Phase I: One Year Analysis of Existing Resources"

[3] Rebuttal Testimony (Apollo-RT-5) of Carl Freedman on PUC Docket 00-0135 (Oct. 2000)

B. HECO

HECO/HREA-DT-IR-1 <u>**Ref: HREA-T-1, Page 8, Lines 14-16**</u>

Please explain HREA's understanding of costs of a power purchase agreement that are reflected in utility rates.

HREA Response: HREA understands that when the utility purchases power from an Independent Power Producer (IPP), the utility pays the IPP the utility's avoided cost as negotiated in the power purchase agreement with the IPP. When the utility forwards the IPP contract to the PUC for approval, the utility seeks recovery of IPP payments as part of the fuel adjustment clause until such time the payments can be rolled in the rate base. In the case of a windfarm that is a Qualified Facility (QF) under PURPA, the utility will seek recovery of energy payments in utility's rate base application to the PUC. The energy costs (weighted average fuel costs plus some O/M) are the basis for recovery.

HECO/HREA-DT-IR-2 <u>**Ref: HREA-T-1, Page 9, Lines 16-18**</u>

Please explain the basis for the statement that "the Companies have access to lower cost financing". Please provide specific examples.

HREA Response: The Companies could seek approval from the PUC to issue special revenue bonds. The utility has bond rating (s) based on the utility's profitability as well as physical plant value. Generally because the Companies have a monopoly, as well as a guaranteed fix rate of return on invested capital, the Companies' ability to debt service the bonds is generally superior (bond rating higher resulting in lower interest costs) to other entities including some State and local government agencies.

Very few, if any, third Parties could obtain approval and qualify for special revenue bonds.

HECO/HREA-DT-IR-3 <u>**Ref: HREA-T-1, Page 9, Lines 23-25**</u>

a. Is it HREA's belief that the Companies have intimate knowledge of a customer's energy usage beyond the meter?

HREA Response: Yes.

b. Is it HREA's belief that the Companies have more knowledge of a customer's energy usage beyond the meter than an energy services company ("ESCO")?

HREA Response: Yes.

HECO/HREA-DT-IR-4 **Ref: HREA-T-1, Page 11, Line 15**

Please describe where in the Companies' CHP Program application it is indicated that customer choice would be effectively limited to the Companies' offerings.

HREA Response: The Companies are correct in that there is no statement in the Companies' CHP Program application stating that customer choice would be limited to the Companies' offerings. To clarify, it was Mr. Bollmeier's overall assessment, following a review of the Companies' CHP Program application that customer choice would be limited to the Companies offerings, if the proposed tariff were approved. In large part, Mr. Bollmeier believes the market barriers would severely limit competition. The Companies' own projection of their market share supports his argument. Specifically, as noted in HREA-HECO-T-6-IR (to Bill Bonnent): ".....please explain how HECO's estimate of an 88% utility share of the CHP market (7,700 kW out of 8,700 kW by 2009 per HECO's Exhibit HECO-104) comports with the concept of a competitive market for DG in Hawaii."

HECO/HREA-DT-IR-5 **Ref: HREA-T-1, Page 11, Lines 16-17**

a. If the Companies did not invest in CHP and allowed large customer loads to be lost to non-utility CHP, does HREA believe that ratepayers are better off?

HREA Response: Yes

b. Has HREA conducted any quantitative analysis that compares the impact of lost revenues to the impact of a utility CHP investment? If so, please provide the analysis.

HREA Response: No

HECO/HREA-DT-IR-6 <u>**Ref: HREA-T-1, Page 15, Line 25**</u>

What future rate increases might be seen due to utility revenue losses to independent DG developers?

HREA Response: Given that the Companies are experiencing load growth now and are projecting load growth in the near term, HREA does not believe that utility revenue losses to independent DG developers will result in future rate increases.

HECO/HREA-DT-IR-7 <u>**Ref: HREA-T-1, Page 9, Lines 8-10 and Page 10, Lines 10-12**</u>

HREA states: "In the case of CHP and other non-net-metered technologies, a new competitive market is emerging. However, companies seeking to enter this market, especially those promoting CHP, have experienced barriers including:

* * *

Requirements that third party CHP developers must share competitive information about pending CHP projects with the utility as part of the interconnection agreement negotiation process".

a. Please provide the names of the "CHP developers" that had to share "competitive information about pending CHP projects with the utility as part of the interconnection agreement negotiation process".

b. For each "CHP developer" listed in subpart "a", identify the name of the developer's customer and the location of the CHP project.

c. For each "CHP developer" listed in subpart "a" and installation listed in subpart "b", specify the "competitive information about pending CHP projects" that the "CHP developer" had to share with the utility.

HREA Response: At the present time, HREA cannot answer this question. HREA could answer this question if CHP developers were willing to provide written testimony in response to this and related questions regarding market power issues. However, HREA is not aware of any developers that are presently willing to do so. See also the HREA response to the next IR.

HECO/HREA-DT-IR-8 **Ref: HREA-Exhibit HREA-C, Page 1**

HREA states "Scheibert Energy Company – Hawaii (SECOHI) has estimated they will install 9 MWs over the next 2 years (not included in the Companies' estimate) and will offer 7 year contracts."

a. **Please state the basis for HREA's statement that SECOHI "will install 9 MWs over the next 2 years (not included in the Companies' estimate)". Please (1) provide a copy of any documents relied on by HREA as the basis for HREA's statement, and (2) specify the names of the companies that will have CHP projects (totaling 9 MWs) installed over the next 2 years and the size of the CHP projects that will be installed.**

HREA Response: The information requested in this IR is example of the type of information referred to in the previous IR (HECO/HREA-DT-IR-7). In this case, HREA obtained permission from SECOHI to share a chart (Exhibit B) indicating potential generation/co-generation applications on Oahu and Maui. HREA thanks SECOHI for their willingness to step forward and contribute to HREA's response to this IR. HREA also respects SECOHI's request that the names of the potential customers not be revealed.

b. **Please state the basis for HREA's statement that SECOHI "will offer 7 year contracts." Please provide a copy of any materials relied on by HREA as the basis for HREA's statement.**

HREA Response: The basis for HREA statement that SECOHI "will offer 7 year contracts" is a personal communication with SECOHI.

HECO/HREA-DT-IR-9

HREA's May 7, 2004 Preliminary Statement of Position discussed the fourteen issues set forth in Prehearing Order No. 20922, filed April 23, 2004. Please state whether HREA's position on the fourteen issues has changed from the position set forth in its Preliminary Statement of Position. If the answer is anything other than an unqualified "no", please (1) identify each issue on which there has been a change in position, (2) state and fully discuss each changed position on the issues, and (3) provide the basis for each changed position on the issues (including a copy of any material relied in support of each changed position).

HREA Response: No.

C. HESS-MICROGEN

HESS-DT-1 to HREA Ref.:HREA's DT p.15, lines 18-19

Please explain in detail how HREA believes the utility rate structure must be redesigned to encourage DG.

HREA Response: HREA believes a tiered-rate utility rate structure shows promise for encouraging all customers to implement DG measures. The basic approach in a tiered-rate would be to bill customers at increasing rates for increasing levels of usage. HREA believes this approach, combined with a low customer charge, would encourage customers to implement DG measures to reduce their site load. However, HREA is not prepared at the present time to discuss the issue of utility rate structure redesign in detail. HREA believes design of a tiered-rate would be best approached through a collaborative process involving all interested parties, and inclusion of experts with relevant expertise and experience.

D. Kauai Island Utility Cooperative

KIUC/HREA-DT-IR-2

HREA's Direct Testimonies do not appear to distinguish between KIUC's cooperative ownership structure and the investor-owned ownership structures of the other Hawaii electric utilities. As noted in KIUC's Direct Testimonies, KIUC is a cooperative owned by its member/customers. As a member, these customers are entitled to share in the margins of the cooperative through patronage capital refunds/credits. In the event a member of KIUC decided to install its own DG facilities, this would impair the cooperative's margins, its build-up of equity, and the resulting ability to provide patronage capital refunds to its members. In addition, because KIUC is required to maintain a certain relationship of sales to members versus non-members in order to retain its tax-exempt status, the loss of members to non-KIUC owned DG facilities, where such members for whatever reason decide to forego their membership but remain connected to KIUC's system for back-up or supplemental power, could threaten this tax-exempt status.

a) Given the above, please explain whether a member of KIUC would have less of an incentive to install its own DG system, thus foregoing or reducing its build-up of patronage capital, than if it were a customer of an investor-owned utility.

HREA Response: HREA cannot predict what customers will do or what they might be incentivized to do. However, HREA believes a customer's decision to install its own DG system will be tend to be: (i) independent of whether the customer is a Coop member or a customer of an investor-owned utility, and (ii) based on answering at least these basic questions:

(1) Will the DG system provide the customer with energy savings? Presumably, the answer to this question would be "yes" (for now, HREA will make that assumption);

(2) How much will the customer save now and in the future? The answer to this question does require a clear crystal ball. There will be savings in the near-term, and possibly (HREA believes very likely) greater savings in the future, depending on the Coop's rates;

(3) How do those savings compare with anticipated refunds of his patronage capital? Since HREA does not know what the refunds of patronage capital would be, HREA cannot comment on what the real trade-off would be for the customer, i.e., would he lose money initially based on his energy savings vs. less patronage capital refund;

(4) How much does the customer have to invest or what are the terms of an agreement that the customer would need to sign with a third party? HREA believes many, if not most, customers are more likely to "lease" rather than "purchase" DG systems (especially CHP), and thus would not have to make a large upfront investment;

(5) How long a view does the customer take when making an investment? Conventional wisdom would dictate that customers look at the near-term, i.e., will their investment pay back in a low number of years? However, with the availability of third-party financed and operated systems and/or other financial incentives, HREA believes customers will take a longer-term view (again, especially for CHP); and

(6) What other factors does the customer take into consideration? For example, if a customer is interested in doing his share to protect the environment and/or to reduce Hawaii's fossil fuel use and/or take advantage of government or utility incentives, HREA believes he is quite likely to take a longer-term view. In that case, HREA believes the customer's longer-term view may lead the customer to forgo a portion up to all of his patronage capital refunds.

b) Please explain whether the above supports the ownership of DG facilities by KIUC in order to protect KIUC's build-up of equity, the continued availability of patronage capital refunds to its members, as well as KIUC's tax-exempt status.

HREA Response: HREA believes that the question of ownership of DG facilities by KIUC revolves around two key market issues: first, is implementation of DG a natural monopoly, and, second, is there the basis for a competitive market on Kauai. First, HREA believes that implementation of DG is not a natural monopoly, and, second, there is a strong basis for a competitive market on Kauai, primarily because of Kauai's high rates, there is a strong incentive for customers to look for lower-cost alternatives, which bolds well for a competitive market.

Given that, the next question is how can KIUC's interests be protected given the stated concerns above regarding build-up of equity (BOE), continued availability of patronage capital refunds (PCFs) to its members, and protection of KIUC's tax-exempt status?

BOE and Availabilty of PCFs to KIUC's members. HREA believes that KIUC is faced with a similar decision as individual customers regarding implementation of DG. Specifically, does KIUC invest Coop dollars in DG or lose revenues as third-party DGs come on-line? Either way, there is a threat to the BOE and PCFs. HREA believes this issue might be well put to KIUC's members – should DG investments be made at the expense of the build-up in equity and the PCFs? HREA believes that KIUC investments will be greater than the revenues lost from third Party DGs, which would then have a greater impact on the BOE and PCFs. In addition, if the KIUC members and the Coop management take the longer view, then HREA believes DG investments, especially through third parties, make a lot of sense.

KIUC's Tax-Exempt Status. HREA cannot address this issue regarding KIUC's tax-empt status, as KIUC has not indicated what the threshold issues are, e.g., at what level of sales to members versus non-members would be trigger loss of the tax-exempt status?

END OF HREA'S RESPONSE TO IRs FROM THE VARIOUS PARTIES

DATED: August 18, 2004, Honolulu, Hawaii

President, HREA

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing "Response to IRs from Various Parties" upon the following parties by causing a copy hereof to be hand-delivered or mailed, postage prepaid, and properly addressed the number of copies noted below to each such party:

Party		Party	
DIVISION OF CONSUMER ADVOCACY 335 Merchant Street Room 326 Honolulu, HI 96813	3 copies	BRIAN T. MOTO, CORPORATION COUNSEL County of Maui Dept. of the Corporation Counsel 200 S. High Street Wailuku, HI 96793	1 copy
THOMAS W. WILLIAMS, JR. ESQ. PETER Y. KIKUTA, ESQ. Goodsill, Anderson, Quinn & Stifel Alii Place, Suite 1800 1099 Alakea Street Honolulu, Hawaii 96813	1 copy	CINDY Y. YOUNG, DEPUTY CORPORATION COUNSEL County of Maui Dept. of the Corporation Counsel 200 S. High Street Wailuku, HI 96793	1 copy
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Party		Party	
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LANI D. H. NAKAZAWA, ESQ. Office of the County Attorney County of Kauai 4444 Rice Street, Suite 220 Lihue, HI 96766	2 copies		

Dated: Augus 18, 2004

President, HREA

EXHIBIT A

California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis

PHASE I: ONE YEAR ANALYSIS OF EXISTING RESOURCES

RESULTS AND RECOMMENDATIONS

FINAL REPORT • FINAL RELEASE

PREPARED FOR

The California Energy Commission
The California Public Utilities Commission

PREPARED BY

Brendan Kirby
Oak Ridge National Laboratory

Michael Milligan
National Renewable Energy Laboratory

Yuri Makarov and David Hawkins
California ISO

Kevin Jackson and Henry Shiu
California Wind Energy Collaborative

DATE

December 10, 2003

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EXECUTIVE SUMMARY

This report presents the results of Phase I of the California Renewables Portfolio Standard (RPS) Renewable Generation Integration Costs Study. The study is sponsored by the California Energy Commission in support of the California Public Utilities Commission's RPS implementation efforts. The goal of the study is to develop a methodology for determining the integration costs of California RPS eligible renewable generation projects. The study is motivated by the RPS's "least-cost, best-fit" bid selection criterion which requires that indirect costs be considered in addition to the energy bid price when selecting eligible renewable projects. The methodology will produce cost adders which can be added to a project's bid price during the bid selection process.

Integration costs are a subset of indirect costs and are defined as the costs and values of integrating an electrical resource such as a generation project into a system-wide electrical supply. Three primary categories of integration costs have been identified: capacity credit, regulation cost, and load following cost.

In Phase I of the study, the integration costs of California's renewable generation in 2002 was examined. Analyzing the existing installation of renewable generation provided an important basis for understanding the pertinent issues surrounding the study and a foundation for the remainder of the study which addresses new projects. Additionally, the Phase I results provide some values which can be applied immediately to RPS bid selection while the methodologies are refined and finalized in the subsequent phases of the study.

The following sections present the Phase I findings for each category of integration cost.

Capacity Credit

Resource	Relative Capacity Credit
Medium Gas	100.0%
Biomass	97.8%
Geothermal (constrained)	73.6%
Geothermal (unconstrained)	102.3%
Solar	56.6%
Wind (Altamont)	26.0%
Wind (San Gorgonio)	23.9%
Wind (Tehachapi)	22.0%

The capacity credit of a generator, while categorized as an integration cost, is not a cost at all. Instead, it is the value of a generator's contribution to the reliability of the overall electrical supply system. Relative capacity credit values based on a gas reference unit were determined for various renewable technologies.

A reliability model of the generation supply system was developed based on data from the California ISO (CaISO) and from a commercial generator reliability database. The model was calibrated and generator reliability metrics were calculated. As detailed further herein, maintenance outage scheduling was excluded from the calculation.

Relative capacity credit values are shown in the table above. As expected, the biomass and geothermal resources have high capacity credit values (in the absence of fuel or other constraints) because they behave most like conventional resources. The wind capacity credit is significantly lower than the other resources, but shows that wind can help reduce system risk, albeit by a modest amount when compared to other resource types. The wind capacity credit values are consistent with what we would find for a conventional unit with a very high forced outage rate — about 75%.

During the 12 September 2003 public workshop and the public draft review period of this report, several parties commented (see Appendix C) that the solar capacity credit value was lower than they expected. As discussed in Section C.1.1, there are several possible reasons for this. However, until sufficient analysis is performed to verify the cause of the perceived discrepancy, the solar capacity credit value of 56.6% should not be applied toward any RPS bid evaluation or ranking.

A preliminary investigation of the effect of increasing penetration was performed by doubling the hourly output levels of each of the renewables under study. It was determined that the results above are conservative values which will remain applicable for at least a doubling of renewable capacity.

Several items have been identified for investigation in the subsequent phases of the study. First, as originally planned for Phase II, a thorough analysis of the effects of increased penetration, different technologies, siting, and various other parameters will be performed. Calculations will employ disaggregated data whenever possible so that differences between individual generators can be captured. Second, a simplified method for calculating the capacity credit will continue to be pursued. Third, a monetary value will be determined for the capacity credit so that a cost adder can be derived.

Regulation

Resource	Regulation Cost ($/MWh or mills/kWh)
Total Load	-0.42
Medium Gas	0.08
Biomass	0.00
Geothermal	-0.10
Solar	0.04
Wind (Altamont)	0.00
Wind (San Gorgonio)	-0.46
Wind (Tehachapi)	-0.17
Wind (Total)	-0.17

The generating resources studied have quite minor impacts on the total system regulation requirements. The sheer size of the load results in a regulation cost for the aggregated load that is essentially identical to the total system regulation cost.

An important note is that all of the results are quite small. They are, at best, at the edge of the error range for this data. We can clearly say that the impacts of the individual resources are not significantly larger than what is shown. However, it is difficult to have confidence in the precision of these small numbers. The CaISO data storage system was not designed to maintain the level of resolution needed for the analysis of small fluctuations.

Given the caution on the precision of the results, it is not surprising that both the medium gas plant and the solar plant have slightly positive numbers. The daily solar cycle tends to follow the daily load pattern. This primarily helps with load following and improves the performance of the solar plant in the energy market. A small benefit also flows into the regulation performance. Similarly, the medium gas plant tends to chase the energy market price, helping load following. A small portion of this benefit also flows into regulation performance.

Not unexpectedly the wind plants impose a small regulation burden on the power system. This was expected because there is no apparent mechanism that would tie the wind plant performance to the power system's needs in the regulation time frame and result in a benefit like there is for solar plants or conventional plants that are following price signals. The regulation burden is low because there is also no mechanism that ties wind plant fluctuations to aggregate load fluctuations in a compounding way either. Wind and load minute-to-minute fluctuations appear to be uncorrelated. Hence they greatly benefit from aggregation. In aggregate, the wind regulation burden is lower (on an energy basis) than that imposed by loads. Interestingly there is a range of regulation performance that may be related to the geographic location of the wind plants.

The geothermal plant also shows a small regulation burden. Most of the time the geothermal plant has steady output and would be expected to impose little or no regulation burden. Examination of the time series data shows that there are times when output from the geothermal plant becomes somewhat erratic, possible explaining the slight regulation burden seen here.

The biomass plant output was steady and imposed no regulation burden.

This preliminary analysis shows that there is little regulation impact imposed on the CaISO power system by the existing renewable resources. These results are sufficiently robust so that little impact should be expected if reasonable amounts of additional renewable resources are added to the system. The calculated impacts are close to the limits of the study accuracy.

It appears that different wind locations may have different regulation performance. This will be studied further in Phase II. Similarly, the overall study accuracy should be refined. One minute data on total system load and each of the resources should be collected and saved at higher resolution than the current system accommodates. Analysis should be performed quarterly and annually to update this report.

Load Following

The load following analysis in this effort focused on implicit costs associated with integration of renewable energy. Explicit, market settled costs were not considered. Integration of large amounts of renewable generators could potentially increase errors between scheduled and actual generation. Increases in scheduling error could potentially change the composition or size of the BEEP stack, the generator pool used to compensate for scheduling deviations. If such a distortion of the stack occurred it could shift the market to marginal generators, whose costs were higher. That could increase the price of energy in the market and thus create implicit costs which were imposed on the system by the renewable generators.

RESOURCE	COMBINED FORECAST ERROR AND RENEWABLE SCHEDULING ERROR			
	Average Minimum		Average Maximum	
	MW	Compared to forecast error w/out renewables (%)	MW	Compared to forecast error w/out renewables (%)
Forecast error without renewables	-1909	100%	2220	100%
Biomass	-1897	99%	2218	100%
Geothermal	-1878	98%	2221	100%
Solar	-1870	98%	2220	100%
Wind (Altamont)	-1909	100%	2272	102%
Wind (San Gorgonio)	-1898	99%	2226	100%
Wind (Tehachapi)	-1884	99%	2281	103%
Wind (total)	-1870	98%	2377	107%
Scheduling bias	-5076	266%	1747	79%

The analysis methodology first determined system forecasting and scheduling errors for the benchmark case without renewable generators. The scheduling coordinators typically schedule significantly less generation than is needed for on-peak load and rely upon the hour ahead market to provide the balance. The difference between the forecast load and the scheduled load is defined as the scheduling bias. Forecast and scheduling errors in the benchmark case provide an indication of the variability inherent in operating the utility grid and are important because they define the normal range of errors without renewable generation impacts.

The next stage of the analysis was to calculate the scheduling errors for each renewable generator of interest. Worst case scheduling was used to estimate the impacts of the renewable generators. The analysis is therefore conservative

The total forecasting error including the renewable resources was calculated by combining the system forecasting error (without renewables) with the additional scheduling error produced by the renewable resource in question. The forecasting error including renewable generators was then compared against the benchmark case and reviewed to identify the significant differences between them. The goal of this analysis was to determine if the renewable resources significantly changed the forecasting error and modified the generator bid stack.

Based on the results of this analysis, the impacts of renewable generators are small when compared against the bias introduced by the scheduling coordinators. As discussed above, the scheduling bias provides an indication of the depth of the BEEP stack. Therefore impacts which are small relative to the scheduling bias were not considered to significantly change the stack size or composition. These results indicate that renewable resources have no significant impacts on the stack at current levels of market penetration and are sufficiently robust so that little impact should be expected if reasonable amounts of additional renewable resources are added to the system.

More detailed analyses are recommended for the subsequent phases of this study to evaluate the effects of increased renewable penetration and the impacts on contingency reserves.

Generic Distributed Generation Units
Confidential Customer Sites
23 April 2004

EXHIBIT B

GENERATION/COGENERATION BUSNESS DEVELOPMENT MATRIX							
						300kW	LF=0.75
#	Customer	Island	Power	Heat	Cool	Units	TOTAL kW
1	Confidential	Oahu	X			13	2,925
2	Confidential	Oahu	X			13	2,925
3	Confidential	Oahu	X	X		3	675
4	Confidential	Oahu	X	X		4	900
5	Confidential	Oahu	X	X		4	900
6	Confidential	Oahu	X	X		1	225
7	Confidential	Maui	X	X		2	450
8							-
9							-
	TOTAL					40	9,000