Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

September 26, 2005

William A. Bonnet
Vice President
Government & Community Affairs

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PUBLIC UTILITIES
COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Attention: Catherine P. Awakuni

Dear Ms. Awakuni:

Subject: Comments Relating to the RPS Second Concept Paper

Pursuant to the Commission's letter dated July 26, 2005, Hawaiian Electric Company, Inc. ("HECO") respectfully submits its comments to the Commission's RPS Second Concept Paper.

If you have any questions regarding this matter, please contact Dean Matsuura at 543-4622.

Sincerely,

Attachments

cc: Division of Consumer Advocacy

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

Hawaiian Electric Company, Inc.
Comments on Economists Incorporated's
Second Concept Paper dated July 26, 2005
"Proposals for Implementing Renewable Portfolio Standards in Hawaii"

Act 95, S.L.H. 2004, Relating to Renewable Portfolio Standards Workshops October 3-4, 2005

September 26, 2005

These comments are respectfully submitted on behalf of Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Limited ("MECO") (collectively referred to as "the HECO Utilities" or "the Companies").

<u>Second Concept Paper</u>

The Second Concept Paper ("SCP") identifies and describes seven incentive regulation ("IR") mechanisms. Three are based upon Economists Incorporated's ("EI") review of renewable portfolio standards ("RPS") programs in other states, which the SCP surveys in some depth. According to the SCP, the last four mechanisms were specially developed for consideration in Hawaii, and are intended to be "extensions or variations of the first three and take into account the legislative mandate of the Commission and the specific features of the power markets in Hawaii." SCP Executive Summary ("ES"), page v.

The SCP recognizes that the "first and a necessary condition for the adoption of an IR mechanism is the presence of a legislative authority that makes its usage possible." ES, page iii. The SCP also explains that:

> The first defining characteristic of an RPS legislative mandate is how renewable energy target levels are defined. Regime definitions may be flexible or rigid. Flexible regimes do not require a strict correspondence between the physical generation of renewable energy in the state and the target level of renewable energy under the RPS. Rigid regimes require the achievement of the renewable energy targets through the actual generation or procurement of renewable energy in a particular year.

ES, page iii. The SCP explains that another defining characteristic of an RPS legislative mandate is the scope of the authority it endows the regulator, such as the power to collect and allocate funds.

In addition, the SCP recognizes that "another set of conditions for the adoption of any of the three IR mechanisms is their appropriateness to or consistency with the characteristics of the state's electric power market." The characteristics of power markets on the mainland were described, which appear to be very different from the power markets in Hawaii. ES, page iii.

Exhibit A provides comments on each of the seven IR mechanisms identified for consideration. The seven IR mechanisms described in the SCP include the following:

1. Renewable Energy Credit ("REC") Trading. Under this mechanism, an electricity supplier may purchase RECs in order to meet some or all of its RPS

requirements. A utility can meet its RPS requirements by acquiring a sufficient number of RECs obtained from the unbundled attributes of its own renewable energy generation, or from renewable energy generators, specialist brokers, or purpose-built REC markets.

2. Alternative Compliance Fees. Under this mechanism, utilities can meet the RPS through the payment of fees to a renewable energy development fund. The fund may be earmarked to support investments in renewable energy projects pursuant to specified rules. To serve its load under the RPS requirement, a utility has a choice between acquiring renewable energy generation and paying the fees.

3. Penalties. Utilities are charged a fine for energy generation that falls short of the RPS. To serve its load under the RPS requirement, a utility has a choice between acquiring renewable energy generation and paying the fine.

4. Estimated Avoided Cost of Generation Mix. The SCP indicates that the avoided cost estimate provided by the utility is the price at which a renewable energy resource, whether utility owned or from an independent developer, is paid. Renewable energy resources are added until the RPS is satisfied. The utility bears the risk of an avoided cost estimate that is "artificially" high or low.

5. Commission Estimate of Avoided Cost, Through Collaborative Process. The SCP indicates that the PUC's avoided cost estimate becomes a "benchmark" for comparing the utility's cost of acquiring renewable energy resources. If the avoided cost estimate exceeds the cost of the renewable energy resource, then the utility is allowed to recover a reasonable share of the difference from ratepayers. If

the avoided cost estimate is less than the renewable energy resource cost, then the power plant associated with the PUC's avoided cost estimate, rather than the renewable energy resource, would be installed. The PUC may grant a temporary waiver to a utility that is unable to satisfy the RPS cost-effectively.

6. Dollar Penalty. A dollar penalty would be set at an "efficient" level, that is, "the cost to society of the utility not achieving the RPS." One possible measure of the penalty identified by the SCP is "the incremental benefit to the utility of violating the RPS." Such a penalty would be derived from "the revealed profit-maximizing behavior of the utilities . . . ." The SCP indicates that a penalty could be designed to "minimize the incremental benefit from violating, subject to the regulatory condition that the utility continues to have the opportunity to earn a reasonable rate of return."

7. Incremental Benefit Due to Multiplier Effect. Under this IR mechanism, the utility is allowed to recover both the renewable energy resource cost and a reasonable share of the "incremental benefit due to the multiplier effect." If the marginal generation technology is more expensive than the renewable energy resource, then the utility already has an incentive to install the renewable energy resource and no payment is provided.

Hawaii RPS Law

Hawaii's renewable portfolio standards ("RPS") law was enacted by Act 272, 2001 Hawaii Session Laws ("Act 272"), and amended by Act 95, 2004 Hawaii Session Laws ("Act 95"). The RPS Law, and its legislative history, are discussed in Exhibit B. There are various aspects of the law, and other on-going

Commission proceedings and processes that should be further considered in developing the IR mechanisms. These include:

1. Incentives and Penalties. The Legislature considered, but rejected, renewable portfolio standards "enforced" by penalties. Instead, the second section of Act 95 directs the Commission to develop and implement a utility rate-making structure, by December 31, 2006, which may include but is not limited to performance-based ratemaking ("PBR"). The IR mechanism(s) adopted by the Commission must be consistent with the Legislative intent. In addition to cost-of-service rate regulation and PBR, the IR mechanisms considered should include mechanisms for shareholder incentives, assurances of cost recovery for prudent investments and contracts that are approved by the Commission, mechanisms to expedite approvals of the contracts and recovery of the costs under the contracts, and mechanisms to ensure uniform treatment of customer alternatives if utility prices increase as a result of meeting the renewable portfolio standards.

2. Utility Profitability and Risk. Act 95 directs the Commission to determine the extent to which any proposed utility ratemaking structure would impact electric utility company profit margins, and to ensure that these profit margins do not decrease as a result of the implementation of the proposed ratemaking structure. There need to be assurances that prudently incurred costs will be recoverable in the future, and the ability to receive incentives that offset the risks incurred in pursuing renewable energy resources.

3. Utility System Impact. Act 95 explicitly points to factors such as the impact of renewable energy resources on utility system reliability and stability. The

ratemaking structure adopted pursuant to Act 95 needs to take impacts and constraints related to renewable energy resources into consideration. This is best done in the integrated resource planning ("IRP") process

4. Cost Effectiveness. The Hawaii Legislature opted to promulgate renewable portfolio standards that would either be achieved in a "cost-effective" manner, or would be revised. A utility cannot take into account the beneficial attributes of renewable resources by simply boosting the avoided cost price paid to renewable resource producers by the amount of an "externalities adder". On the other hand, it does appear that the utility can incorporate specific resources, or types of resources, in an IRP Plan, based on the attributes of those resources and the degree to which they help the utility achieve the goals and objectives specified for the IRP Plan. Thus, it appears that the utility can establish "set asides" as part of its IRP Plan for resources that will allow the utility to obtain the designated attributes, as long as the set asides do not arbitrarily exclude other resources that would provide the same attributes. By doing this in the IRP process, all of the factors deemed significant by Act 95 can be taken into consideration, and IR mechanisms can be targeted to the specific resources to be acquired.

5. DBEDT and DLNR. Act 95 added provisions to Hawaii law requiring that actions be taken by the Department of Land and Natural Resources ("DLNR") and the Department of Business, Economic Development, and Tourism ("DBEDT"). This provision, along with other provisions in the Act, explicitly recognizes that there are factors besides utility actions that will impact the ability to achieve the renewable portfolio standards. The ratemaking structure and IR mechanisms need to take into

account these other factors.

6. Consolidated Utility. The RPS law addresses the possibility of achieving the renewable portfolio standards on a consolidated-company basis, rather than on an island-basis.

7. Energy Conservation. Act 95 broadened the definition of "renewable energy" to include energy conservation resources. The ratemaking structure must provide incentives to implement all of these measures, to the extent they are cost-effective.

8. On-Going PUC Proceedings and Processes. The RPS discussion needs to be coordinated with other on-going generic investigations and PUC-mandated processes that will impact the utility's ability and incentives to achieve the renewable portfolio standards, including (1) the distributed generation (DG) investigation docket and suspended Combined Heat and Power ("CHP") Program application docket, (2) the Energy Efficiency Docket, (3) the Competitive Bidding Docket, and (4) the electric utilities' on-going IRP processes.

The SCP briefly describes most of these aspects of Act 95[1], but does not appear to give them much weight or consideration in developing and discussing the seven IR mechanisms. Each of these is discussed in more detail below.

Incentives and Penalties.

The Legislature considered, but rejected, renewable portfolio standards "enforced" by penalties. Instead, the second section of Act 95 directs the Commission to develop and implement a utility rate-making structure, by December

[1] ES, page ii.

31, 2006, which may include but is not limited to performance-based ratemaking ("PBR"), to provide incentives to encourage Hawaii's electric utility companies to use cost-effective renewable energy resources found in Hawaii to meet the renewable portfolio standards.[2] The implicit assumption of this provision is that the form of regulation (i.e., the regulatory regime) can favorably impact the achievement of the renewable portfolio standards. In essence, the Commission is asked to look at incentive-based regulation, as an alternative to the traditional command and control form of regulation, in which the Commission directs the utility to do certain things, and imposes penalties if those things are not done.

The IR mechanism(s) adopted by the Commission must be consistent with the Legislative intent. In addition to cost-of-service rate regulation and PBR, the IR mechanisms considered should include mechanisms for shareholder incentives (such as those for the existing demand-side management ("DSM") programs and/or the proposed DSM programs), legislative and/or PUC assurances of cost recovery for prudent investments and contracts that are approved by the Commission, mechanisms to expedite approvals of the contracts and recovery of the costs under the contracts (such as a file and suspend mechanism for contracts that meet established parameters), and mechanisms to ensure uniform treatment of customer alternatives if utility prices increase as a result of meeting the renewable portfolio standards.

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[2] PBR was the only mechanism identified by name in the law for consideration by the Commission. Performance based ratemaking generally identifies performance criteria and incentives for exceeding targets as well as penalties for falling short.

Section 1 of Act 95 addresses the importance of export expansion and import substitution as a basis for increasing the development of renewable energy in Hawaii. The SCP does not discuss the source of capital for renewable energy projects and how to encourage that that capital be generated and retained within the state. Since most renewable energy projects are by their nature capital-intensive, the flow of that capital is critical to achieving the economic goals identified in Section 1. What incentives may be appropriate to encourage internal capital formation in Hawaii for renewable energy projects?

Utility Profitability and Risk.

In developing and implementing a ratemaking structure to provide incentives that encourage Hawaii's electric utility companies to use cost-effective renewable energy resources to meet the renewable portfolio standards, Act 95 directs the Commission to determine the extent to which any proposed utility ratemaking structure would impact electric utility company profit margins, and to ensure that these profit margins do not decrease as a result of the implementation of the proposed ratemaking structure. In essence, Act 95 recognizes that the imposition of renewable portfolio standards, and the requirement that utilities take actions to achieve those standards, create certain risks for the utility.

In many instances, renewable resource projects are developed by third parties, who rely on long-term power purchase agreements ("PPA") to be able to finance the projects. The ability to finance projects depends on having a credit worthy off taker, i.e., the utility. Under current regulation, the utility, at best, is able to pass on the cost of purchasing power to its customers (through a number of mechanisms, including the recovery of forecasted capacity payments through base rates, the recovery of certain purchased energy costs that are not included in base rates through the energy cost adjustment clause, and the use of the firm capacity surcharge for non-fossil fuel firm capacity projects between rate cases).

The IR mechanisms proposed in the SCP do not adequately recognize the utility's limited control in bringing renewable energy projects to reality. Most renewable energy is obtained through purchase power contracts. While the utility may enter into a PPA, it does not control the permitting and approvals required for that project, it does not control interaction with the community, and it ultimately does not control whether the developer actually intends to pursue the project or only to add value through permit and approval acquisition such that the project may be sold to another entity. A PPA is the beginning of a process, not the end. To hold the utility financially responsible (as several of the IR mechanisms appear to do) for outcomes it does not control is neither reasonable nor appropriate.

One of the objectives of increased reliance on renewable energy resources is increased price stability for electricity prices. This will not take place unless as-available energy costs for renewable resources are de-linked from oil-based avoided energy costs. Fixing energy prices in a long-term PPA, however, entails risk for the utility, since actual avoided costs may end up being lower than the fixed prices for renewable energy. There needs to be adequate assurances that the utility will be able to recover these costs. (This is not always simple to do. For example, large commercial customers may have alternative sources of electricity, such as customer-sited distributed generation.)

At the same time, long-term PPAs have substantial balance sheet implications, as a result of the manner of which credit rating agencies account for the debt-like characteristics of fixed payments obligations under such contracts, the capital lease implications of some contracts and the potential for some contracts to give rise to "variable interest entities" that must be consolidated with the utility's results of operation.

Thus, risk arises if the utility does not have adequate assurance that it will be able to recover the PPA costs through rates over the long term. The financial markets consider that there is less risk if these assurances are legislative in nature. The ratemaking structure (i.e., the regulatory method used by the Commission to recover costs and provide incentives to achieve the standards) needs to take these risks into account. This applies to the assurances that prudently incurred costs will be recoverable in the future, and to the ability to receive incentives that offset the risks incurred in pursuing renewable energy resources.

Utility System Impact.

Act 95 explicitly points to factors such as the impact of renewables on utility system reliability and stability.[3] It is important to consider constraints that Hawaii's isolated island systems have, and that mainland systems do not have (such as

[3] Under HRS Section 269-95, the studies to be conducted by December 31, 2006, must include findings and recommendations regarding the "capability of Hawaii's electric utility companies to achieve renewable portfolio standards in a cost-effective manner, and shall assess factors such as the impact on consumer rates, utility system reliability and stability, costs and availability of appropriate renewable energy resources and technologies, permitting approvals, impacts on the economy, culture, community, environment, land and water, demographics, and other factors deemed appropriate by the commission . . . ."

limitations on the ability to accept as-available energy generated from renewable resources during minimum peak load periods). (To some extent, these kinds of constraints are addressed through energy storage systems or other load leveling mechanisms.) The ratemaking structure adopted pursuant to Act 95 needs to take these impacts and constraints into consideration.

Cost Effectiveness.

Some states have enacted mandatory renewable portfolio standards that must be achieved regardless of cost. The Hawaii Legislature opted instead to promulgate renewable portfolio standards that would either be achieved in a "cost-effective" manner, or would be revised. The ratemaking structure adopted by the Commission must provide incentives for the implementation of cost-effective renewables.

Act 95 takes into account that the ability to achieve renewable portfolio standards is based on the availability of cost-effective renewable resources, and requires an assessment of factors such as the impact on consumer rates. The Commission is required to do a study to assess the capability of Hawaii's electric utility companies to achieve renewable portfolio standards in a cost-effective manner, and to revise the standards based on the best information available at the time if the results of the studies conflict with the renewable portfolio standards established by Act 95. The Act defines cost-effectiveness in terms of avoided cost.[4] The avoided cost standard is further discussed in Exhibit C. At present the

[4] Under HRS Section 269-91, "cost-effective" means "the ability to produce or purchase electric energy or firm capacity, or both, from renewable energy resources at or below

utility is bound by PURPA to offer to pay avoided cost for any renewable energy project which can meet that test. (In addition, through RHI, the utility has offered to invest equity capital in such projects.) With the price of oil as it is and is expected to be, and the wealth of renewable energy opportunities spoken of in just about every article and report on Hawaii's renewable energy future, one might think project developers would be beating down the door. They are not. This calls into question the economics of renewable energy projects relative to avoided cost, even at its present level, and the practicality (siting/community acceptance) of these projects. Comments on the costs of renewable energy generation resources are provided in Exhibit D.

How can a utility take into account the beneficial attributes of renewable resources in determining the price to be paid to producers of renewable resources, or in determining that the utility itself should implement renewable resources, when the standard of cost-effective is avoided cost?[5]

First, it is clear that the utility cannot be expected to simply boost the avoided cost price paid to renewable resource producers by the amount of an "externalities adder."

Second, the utility cannot be expected to "determine" an independent avoided cost for renewable resources simply by conducting a competitive bid

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avoided costs."

[5] Should a premium be paid above avoided cost? If so, how much and from what source? One might argue that such a premium would serve a public purpose and therefore should be underwritten by taxpayers (through federal and state tax credits), not customers of the utility.

limited to renewable resources.

On the other hand, it does appear that the utility can incorporate specific resources, or types of resources, in an IRP Plan, based on the attributes of those resources and the degree to which they help the utility achieve the goals and objectives specified for the IRP Plan. In other words, it appears that the utility can establish "set asides" as part of its IRP Plan for resources that will allow the utility to obtain the designated attributes, as long as the set asides do not arbitrarily exclude other resources that would provide the same attributes.

The additional benefit of doing this as part of an IRP process is that the utility can take into consideration all of the factors deemed significant by Act 95, and the PUC can approve or modify the resulting plan. IR mechanisms can be targeted to the specific resources to be acquired.

The mechanisms used to acquire the targeted resources also can be determined in the IRP process, which would include a determination of whether competitive bidding should be used.

DBEDT and DLNR.

Section 1 of Act 95 speaks to a partnership between the public and private sectors to increase renewable energy in Hawaii. The IR mechanisms would in turn extract money from the shareholders or customers of the electric utility. The IR mechanisms do not address the partnership articulated by lawmakers in Act 95.

Act 95 also added provisions to Hawaii law requiring that actions be taken by DLNR and DBEDT. This provision, along with other provisions in the Act, explicitly recognized that there are substantial other factors besides utility actions that will impact the ability to achieve the renewable portfolio standards. These include factors such as land use policy, permitting, and community concerns. The ratemaking structure and IR mechanisms need to take into account these other factors.

Also, while the Commission is addressing those areas of the law for which it is directly responsible, consideration should be given to whether parallel efforts are underway in the DLNR and DBEDT to implement their mandates under the law. It is clear that lawmakers envisioned an integrated effort by government in inventorying renewable resource opportunities, expediting permitting and approvals for these projects, actively seeking federal monies for energy programs, and demonstrating leadership by example through energy conservation and efficiency in government facilities. These are efforts which lawmakers recognized as critical to the success of renewable energy, and they are efforts which can only be undertaken by government.

Should the state take an active role in encouraging community acceptance for renewable projects (such as an Oahu wind farm)? Should the State establish resource zones for forms of renewable energy other than geothermal? As things stand now, the project developer and the utility (which incorporates renewable energy projects into its planning) often are left to "try their best, and if it doesn't work out, try somewhere else".

Consolidated Utility.

The RPS law addresses the possibility of achieving the renewable portfolio standards on a consolidated-company basis, rather than on an island-basis.[6] If the potential exists to develop a higher percentage of renewables on the Big Island and/or Maui, then some mechanism needs to be considered as to how Oahu ratepayers could share in that cost (if the ability of their utility, HECO, to meet the renewable portfolio standards depends on the development of renewable resources on the Islands of Hawaii and Maui).

Energy Conservation.

Act 95 broadened the definition of "renewable energy" to include energy conservation resources, in addition to renewable energy generation, and electrical energy savings brought about by the use of solar and heat pump water heating. The ratemaking structure must provide incentives to implement all of these measures, to the extent they are cost-effective.

The IRP Framework already recognizes a number of forms of utility incentives to encourage conservation measures that are encompassed within demand-side management programs. These include: (1) Granting the utility a percentage share of the gross or net benefits (shared savings); (2) Granting the utility a percentage of certain specific expenditures (mark-up); (3) Allowing the utility to earn a greater than normal return on equity for ratebased expenditures (rate base bonus); and (4) Adjusting the utility's overall return on equity in response to quantitative or qualitative evaluation of performance (e.g., adjusting the return upward for achieving a certain level of savings) (ROE adjustment). (IRP

[6] Under HRS Section 269-93, "[a]n electric utility company and its electric utility affiliates may aggregate their renewable portfolios in order to achieve the renewable portfolio standard."

Framework, Paragraph III.f.3.a.) All of these recognized mechanisms should be given consideration.

HECO utilities are currently incentivized for pursuing DSM through the recovery of program costs, lost margins, and shareholder incentives. These incentives are authorized by the Commission's IRP Framework to encourage and reward aggressive utility pursuit of DSM programs. The Energy Efficiency Docket, Docket No. 05-0069, will be examining DSM utility incentives further.

The level of utility DSM efforts is currently defined through the IRP process and is reviewed by the community in IRP Advisory Group and IRP DSM Technical Committee meetings. In the IRP the target levels for DSM are determined based on market potential, cost-effectiveness of the DSM programs, and the resources available to implement DSM. The Energy Efficiency Docket will also be examining "Whether energy efficiency goals should be established, and if so, what the goals should be for the State".

In Hawaii, DSM resources have traditionally been acquired through utility programs, which have been in place since 1996. Through 2004, HECO's Oahu DSM programs have successfully reduced load by 38 megawatts ("mw") (net of free-riders). The Energy Efficiency Docket will also be examining "What market structure(s) is the most appropriate for providing these or other DSM programs (e.g., utility-only, utility in competition with non-utility providers, non-utility providers)."

Thus, the Energy Efficiency Docket and IRP are existing venues in which the appropriate amount of DSM is evaluated. What is the relationship of the Energy

Efficiency Docket and IRP to the efforts under Act 95?

The option of set-asides has been introduced in this discussion. If there is a set-aside for renewables, should the set-aside include energy efficiency as well, given the definition of renewables in Hawaii's RPS law? If so, would a possible option be to identify the energy efficiency set-aside separately from the supply-side set-aside?

On-Going PUC Proceedings and Processes.

The RPS discussion is not explicitly coordinated with other on-going generic investigations and PUC-mandated processes that will impact the utility's ability and incentives to achieve the renewable portfolio standards. These include (1) the DG investigation docket and suspended CHP Program application docket, since the use of waste heat from CHP Systems is included in the definition of renewable energy, (2) the Energy Efficiency Docket, in which new energy efficiency DSM programs and utility incentives are being considered, (3) the Competitive Bidding Docket, and (4) the electric utilities' on-going IRP processes.

The Companies' positions in the Competitive Bidding Docket, as they relate to this proceeding, are briefly summarized in Exhibit E. Some of the key elements of the Commission's IRP Framework are discussed in Exhibit F. A brief discussion of the multiplier effect, and the economic impact analyses done for HECO as part of its IRP processes, are included in Exhibit G.

Incentive Regulation Mechanisms in Economists Incorporated's

Second Concept Paper dated July 26, 2005

"Proposals for Implementing Renewable Portfolio Standards in Hawaii"

Act 95, S.L.H. 2004, Relating to Renewable Portfolio Standards Workshops October 3-4, 2005

Introduction

By way of introduction, some background on Renewable Portfolio Standards ("RPS") and Renewable Energy Certificates ("RECs") on the mainland may be useful. Renewable Energy Certificates are the formal means adopted to represent, and to register the ownership of, the environmental attributes of each kilowatthour of electric energy from a renewable energy project. The registration systems are set up as a common program feature of Renewable Portfolio Standards on the mainland. The certificates are created and registered to allow trading of the certificates. A REC trading system is thought to facilitate the cost-effective satisfaction of RPS requirements. A marketplace of REC buyers and REC sellers determine the price of compliance. Like any marketplace, the larger the number of buyers and sellers, the more likely it is that the price fairly and accurately reflects the costs of compliance.

In general, the economic expectation embodied in the RPS legislation is that the costs of renewable projects exceed the market value of the electric products associated with the projects. Incurring the excess costs is implicitly mandated by the RPS legislation. The REC value will be a marketplace evaluation of those excess costs. In this regard, REC sales proceeds clearly support renewable energy projects. The value of the RECs is enhanced by the number of buyers and several factors which may be at work in the electric marketplace affect the number of buyers. REC buyers generally fall into two categories, mandatory buyers subject to RPS obligations and voluntary buyers who wish to support renewable power financially.

REC trading systems are often created at the time of retail re-structuring or "retail choice". Competitive retail electric suppliers are expected in the re-structured market and represent potential mandatory REC buyers. Many such suppliers will not be engaged in the development or ownership of generation. Retail marketers especially, but also others, such as utilities which remain obligated under so-called "basic" or "default" service to supply part of their retail load, may be more interested in satisfying their RPS obligations by purchasing RECs from generators than by developing renewable projects. REC buyers who are obligated under the RPS program can combine REC purchases with their purchases of electric energy from other sources and achieve compliance without actually fitting renewable energy, with its unique characteristics, into their supply plans. A fully developed REC market would offer REC buyers a choice of contract terms for short, medium or long term purchases of RECs consistent with the expectations of the buyers with respect to their retail customer load.

Voluntary REC buyers include (i) competitive suppliers in re-structured retail markets subject to a RPS program who purchase more than their mandated percentage of RECs in order to market "green power"; (ii) utilities, both in re-structured and in traditional monopoly retail markets, which wish to market "green power" in response to customer requests; and (iii) a limited number of retail customers, usually large and sophisticated industrial, commercial or institutional end-users, which recognize that REC purchases support the development of renewable projects and can do so without requiring them to change suppliers or otherwise deal with the complications of direct electricity purchases from renewable projects. In order to enhance value, renewable project owners will seek buyers in all voluntary REC markets that may exist. Voluntary REC buyers may buy only the RECs and do so intending to "retire" the RECs so that they cannot be "double-counted" and used by an obligated electric supplier to satisfy its RPS obligations.

I. REC Trading Systems

With respect to the first proposal, the Companies have the following comments and/or questions:

1. In the regulated markets in which the Companies operate, the Companies will be the single wholesale purchaser of bulk power and the single retail re-seller of power. The Companies are also, to a significant extent, self suppliers and intend to continue to develop, own and operate generation facilities in appropriate cases in order to meet its obligation to serve retail load on each island. In meeting its RPS obligations, the Companies would expect to build or to buy energy from renewable energy projects and would in each future case, as in past cases, possess or purchase all right, title and interest of an owner in the renewable attributes of the renewable projects. In the case of independently developed and owned projects, owners would face only one party with a mandate to purchase renewable energy, the individual Company. The Companies would be the only entity interested in purchasing in bulk the renewable power as well.

2. It is not yet clear whether, when and to what extent a "green" market of voluntary supporters of renewable energy will emerge in the State. It is not, however, anticipated that a significant number of retail customers would in the near future enter "green power" purchasing programs or fund through bill adders the "retirement" of the environmental attributes of renewable energy projects in order to cause renewable supply to exceed mandated levels.

3. The cost to establish and maintain REC trading systems on the mainland has been significant enough that the costs seem out of line with any foreseeable benefits in Hawaii. Potential REC sellers would at present face a market of one mandated REC buyer and an unknown number of possible voluntary purchasers at some future date. In contrast, mainland REC registration and tracking systems have often been set up and supported by regional organizations, which are able to spread the system's transactional costs. Such regional organizations operate over several states where re-structuring has often occurred and where, as a result, many mandated electric suppliers are expected to emerge as REC buyers.

4. Without incurring the expense of a REC trading system, the Companies, in response to any future customer preferences, could create, like mainland utilities, utility "green power" programs under which customers can opt to support a specified amount of renewable energy through their bills. To the extent of the customers' preferences, the Companies could segregate, or "stream", the costs, and the possible financial benefits, of renewable projects it builds or buys to interested customers. As background, the Companies' Sun Power for Schools green pricing program (installing photovoltaic systems on public schools) is in its 9th year. For the Companies, customer participation has been less than 1 percent (~4,100 customers) and about $426,000 has been collected as of June 2005.

5. While the existence of an effective voluntary REC market with a sizable number of customers could in theory increase renewable energy levels to amounts in excess of RPS requirements, cost effective incentives developed as a result of the instant effort would be directed at the Companies, would be structured and focused by the joint efforts of the present participants and would likely be monitored for effectiveness in the future. Exceeding RPS levels appears to be a more likely outcome of the present endeavor than the potential development of a voluntary market which depends on the high transactional costs of REC registration and tracking. Utility "green power" programs described in No. 4 above could also be specifically designed to achieve success beyond mandated RPS levels.

6. The Companies intend to explore the concept of an inter-company renewable energy credit trading system. Act 95 allows the Companies to consolidate their individual renewable energy portfolios in order to achieve the RPS. As of December 31, 2004, on a consolidated basis the HECO Utilities achieved a RPS percentage of 11.4 % (HECO - 9%, HELCO - 28%, MECO - 12%). If the potential exists to develop a higher percentage of renewables on the Big island and/or Maui, then some mechanism, like an inter-company renewable energy credit trading system, should be evaluated so that Oahu ratepayers could share in that cost (if the ability of their utility, HECO, to meet the RPS to some extent depended on the development of renewable resources on the islands of Hawaii and Maui). The development of a renewable energy credit trading system and its related transfer price mechanism needs to be evaluated with consideration given to issues

such as rate impacts, calculation of avoided costs, administration of such a program and its integration with the development of IRP plans for each respective utility.

II. Alternative Compliance Fees

With respect to the second proposal, the Companies have the following comments and/or questions:

1. Alternative Compliance Payments ("ACP") can function with or without REC trading systems as a "back-stop" on shortages of renewable projects. For example, in the largely re-structured states in New England, renewable projects, and associated RECs, are in short supply due to the inability of renewable developers to obtain long term purchase power agreements suitable for project financing. Other reasons retard development in New England and elsewhere, such as shortages of viable resources and an abundance of project opponents. In New England, on a state by state basis, ACP provide funds, at generally high levels, which can be used by some funding vehicle or entity to assist in the development of projects. The hope is that project shortages will be cured and renewable energy levels will become consistent with state RPS requirements.

2. ACP operate as a "cap" on REC values in any associated REC trading system and take the place of any penalties set at any higher level.

3. The basis for setting ACP levels has not been clear or well understood in many cases on the mainland. In theory, the "cap" might be chosen as the maximum extra cost likely to be incurred in developing the renewable energy project over the value of the energy products from the renewable project. Based on such reasoning, ACP payments in Massachusetts and in Connecticut were set by regulatory approximation and legislative approximation, respectively. Both came out, at least to start, at $50 per megawatt hour (MWH). In Texas and in Pennsylvania, ACP can be set based on a percentage of the market value of RECs - - a challenging proposition for a trading system that is not transparent and is not settled with clearing prices on any REC exchange[1].

4. To be implemented, ACP require authority for collection and authority for expenditure. In light of the relationship of ACP to avoided costs, as discussed below, collection authority may be in doubt without amendment of Act 95. With respect to authority for expenditure, Act 95 is also likely to require amendment. Any such amendment would be required to establish and/or empower some public or quasi-public entity to run a renewable energy assistance program. Experience with such assistance programs on the mainland has been mixed. In any event, transactional costs could be expected to be significant.

5. As presented, the subject proposal anticipates that the Companies would have the choice of the cheaper of two options - - the cost of the renewable energy acquisition, or the sum

[1] REC trading systems have not proven to be liquid enough, with sufficient buyers and sellers, to justify the creation of an exchange system with periodic clearing prices.

of the [ACP] fees and the cost of replacement non-renewable energy. It does not appear that the subject formulation is consistent with the mandate of Act 95, in Section 269-92, that the RPS be met with cost effective resources as defined in Section 269-91 ("at or below avoided costs"). By design, ACP on the mainland have been set to compensate for the lack of cost effective renewable resources and are intended to supplement the value of the energy products from such resources - - a design basis that, at a minimum, requires in this state that legal uncertainties be resolved prior to further consideration.

6. The success of such public funding agencies on the mainland has been hampered by both the lack of expertise and the lack of authority of the public entities involved. In short, public assistance has been no guarantee of success in developing renewable projects. Most such entities, for example, lack the authority to enter into long term contractual commitments to supply funding at the collected ACP levels. Without such levels of commitment, the credit support needed for project financing is often lacking.

7. It would be advisable to focus incentive efforts first on the Companies purchasing or building renewable projects that are cost effective within the meaning of the statute. This would seem preferable to expending time and effort to settle legal uncertainties and then devising an approximation of the appropriate incremental support level which will be collected and spent by an entity, not yet established, and which will have nowhere near the level of the Companies' experience in building or purchasing generation.

III. Penalties

With respect to the third proposal, the Companies have the following comments and/or questions:

1. The proposed design of the penalty proposal shares many features in common with the ACP proposal.

2. The design basis for the level of penalty may or may not mirror the reasoning applied to ACP systems. At any level, it is not clear whether penalties would be recoverable in rates by the fined utility and as a result, would surely produce controversy during both design and implementation.

3. To be implemented, penalties require authority for collection and authority for expenditure. In light of the legislative history of the RPS law and the relationship of penalties to avoided costs, just as discussed above with respect to ACP, collection authority is doubtful. With respect to authority for expenditure, Act 95 is likely to require amendment. A public or quasi-public entity would again be needed to run a renewable energy assistance program. Again, transactional costs could be expected to be significant. Results could be mixed since such entities have a spotted track record on the mainland.

4. As presented, the penalty proposal anticipates that the Companies would have the choice

of the cheaper of two options - - the cost of the renewable energy acquisition, or the sum of the fines and the cost of replacement non-renewable energy. It is not clear that the subject formulation is consistent with the mandate of Act 95, in Section 269-92, that the RPS be met with cost effective resources as defined in Section 269-91 ("at or below avoided costs"). By design, the fines are intended to supplement the avoided cost of non-renewable resources and renewable resources are to be acquired up to the stipulated increment over avoided costs - - a design basis that, at a minimum, again requires that legal uncertainties be resolved prior to further consideration.

5. The Hawaii Legislature explicitly considered, but did not adopt, penalty mechanisms as part of the RPS law. In the 2001 and 2004 Hawaii State Legislative sessions, a number of proposed bills related to RPS were introduced and heard in various committees. Some of these proposed bills contained mechanisms penalizing the electric utility for not achieving the RPS goals on a timely basis. During the various hearings before House and Senate Energy and Environment and Commerce and Consumer Protection Committees, testimonies were heard from utilities, government agencies, private business, other organizations and the general public on the pros and cons of a penalty mechanism in the proposed RPS bills. The original bills were either passed as written, modified (committee draft) or held in committee. To this end, a modified RPS bill, that does not include any penalty clauses, was finally agreed upon in a joint conference committee and the Hawaii State Legislature voted and approved the RPS bill. The Governor signed the RPS bill into law in 2001 as Act 272 and in 2004 as Act 95).

6. In addition to the suspect legality of any proposal to assess penalties or to pay in excess of avoided costs, under the mandate of Act 95, it is likewise questionable whether an incentive explicitly designed to extract a non-recoverable penalty from the utility can ever be consistent with Section 269-95. Absent wanton neglect or willful misconduct or something equally unlikely, it is hard to see how penalties can be designed consistent with the directive "to ensure that [electric utility] profit margins do not decrease". In all events, no penalty could be applied unless both statutory bases in Section 269-92 for being relieved of RPS responsibility were determined to be absent by the Commission.

IV. Utility Estimated Avoided Costs

With respect to the fourth proposal, the Companies have the following comments and/or questions:

1. Under this proposal, it appears that the individual Company could be required to estimate a generic level of "avoided costs" equally applicable to all renewable resources without regard to the resource characteristics of any particular resource such as the firmness or lack of firmness of its capacity, dispatchability or lack of dispatchability, interconnection costs and restrictions, fuel type, size, location and other features which affect the ability of that particular renewable resource to allow the individual Company to avoid costs on its system. As a threshold matter, confirmation is needed that this "one size fits all"

concept is actually intended to apply to all renewable resources, whether solar or wind or landfill gas or the like.

2. As a second threshold issue, the Companies question whether the estimated avoided cost, whether generic or specific, is intended to be disclosed to the public so that potential bidders or negotiating parties would know the Companies estimate in advance of trying to reach any sort of agreement with the Companies, whether the agreement is a power purchase or an asset acquisition or an engineering and construction agreement.

3. As the Companies have often testified, real avoided costs are customized to the resource under consideration for addition to the individual Company's system[2]. Production cost runs are needed with the candidate resource "in" (and assigned zero capital and fuel costs) and the candidate resource "out". A differential revenue requirements analysis establishes that particular resource's avoided costs.

4. Under the subject proposal, the Companies understand that the Companies are intended to be at risk for the accuracy of its estimated avoided costs. The Companies would add renewable resources until the RPS were satisfied. It appears that the Companies would pay the greater of (i) its estimated avoided cost or (ii) the actual cost of the renewable project when the actual cost of the renewable project was the lower of the two costs and then the Companies would recover in rates only the actual lower cost. When the actual cost of the renewable project was higher than the estimated avoided cost, the Companies would recover the lower estimated avoided cost, but experience the actual higher costs building the renewable project. It is assumed in this latter event that the Companies must build the resource since no third party would build and experience the actual higher costs in return for payment of the lower estimated avoided costs. The Companies question whether this understanding is correct or not.

5. If the payment scheme is as described above, Companies shareholders would pay more than actual costs, or recover less than actual costs, for the sole reason that management estimated twenty or more years of system capital and fuel costs and derived in the process a number that did not turn out to be "correct"[3]. The Companies are unaware of any market in any way related to the cost to supply energy in which any participant offers to buy or sell a hedge contract for such a length of time. The subject proposal amounts to such an arrangement. The Companies suggest, respectfully, that the subject proposal would not be workable and may violate applicable statutory and regulatory requirements.

6. There are significant uncertainties at the present time with respect to the determination of

[2] For example, see testimony of Ross H. Sakuda, Docket No. 03-0371, HECO T-3, and HECO-304.

[3] As generally acknowledged in all corners, the only thing that can be known for sure when deriving forecasted numbers over time periods like twenty years is that the forecasted number is wrong. Locking in twenty year forecasts of avoided costs is largely responsible for the high number of purchased power agreements on the mainland that become so-called "stranded costs" when retail re-structuring occurred.

avoided cost, because the effect on avoided cost of financial accounting issues, such as FIN 46R and EITF-01-8, cannot be determined at this time. Please refer to HECO's application for approval of Amendment Nos. 5 and 6 to the Kalaeloa PPA, Appendix C, in Docket No. 04-0320.

7. It is not clear from the proposed IR Mechanism 4 when avoided costs would first be determined and how frequently they would be determined. Currently, avoided costs are determined at the time negotiations occur with IPPs.

8. If avoided costs are adopted as part of IR mechanisms, they should be based on the utility's base resource plan, and be specific to the type of renewable resources to be acquired.

- Integrated Resource Planning ("IRP") should be continued and integrated with any renewables incentive structure adopted by the Commission.
- Avoided costs based on IRP planning for the next units on the system should be derived using the Companies existing differential revenue requirements approach. Note that the IRP Plan does not "fix" the timing of resources in the plan, which may be adjusted as newer planning forecasts are adopted.
- Proposed renewable resources should be analyzed using the Companies "customized" avoided costs so that accurate assessments are made based on the particular resource's unique characteristics.
- Customized avoided costs could be filed under protective cover with the Commission but would not be disclosed to any party in a position to negotiate to supply power, or the renewable asset or construction services with respect to the particular renewable asset.
- The Companies would make a buy or build decision regarding particular assets depending upon all of the facts and circumstances at the time that affect system requirements and the obligation to serve.
- For power purchases, to minimize the "stranded cost" possibilities, the Companies would attempt to avoid "locking in" twenty year projections of fuel costs that are a part of its avoided cost analysis.
- For suitable renewable resources, the Companies could seek to share fuel price risk with project proponents by partially tracking actual "as available" energy costs and partially locking in "floor" prices which allow developers to cover part, but not all, of their capital service requirements solely from the floor component of their prices.
- In order to minimize or eliminate adverse impacts on the Companies' cost of capital, cost recovery should not depart from actual contract purchase prices or construction costs prudently incurred.
- Where savings from avoided costs could be documented, the Companies would receive a portion of the savings as an incentive and the structure would be designed to treat power purchases and Company owned assets as comparably as possible.

V. Commission Estimated Avoided Costs

With respect to the fifth proposal, the Companies have the following comments and/or questions:

1. The subject proposal contemplates that the Commission would derive, in some collaborative fashion, avoided costs for renewable projects. The Companies again questions whether "one size fits all" and if so, what methods are expected to be used to estimate a generic avoided cost.

2. Assuming that any avoided cost, collaboratively derived by the Commission, will be widely known and disseminated among potential contracting parties, the Companies also question as a threshold matter whether it is wise to create avoided costs in such a public fashion. The Companies fear that its ability to negotiate would be compromised by public price information.

3. As a result of the source of the avoided cost estimate, the fifth proposal provides that the Companies are excused from the risks of its inaccuracy. Actual costs of renewable projects below the Commission-derived avoided costs are fully recovered by the Companies, subject to an incentive bonus based on the savings from avoided costs. If the costs of renewable projects are discovered to be higher than the Commission-derived avoided costs, the Companies would be excused from incurring the higher costs and from the related RPS obligation. The unit on which the avoided costs were based would be pursued in lieu of the higher priced renewable project.

4. While certain punitive features of the fourth proposal have been eliminated in this fifth proposal, the Companies continue to believe that customized avoided costs, derived on a protective basis, and based on and integrated with the IRP process, would serve the public's interest in cost effective renewal resources better than the collaboratively derived avoided cost described in this proposal. See: Comment No. 6 under the fourth proposal above.

5. It is not clear that avoided costs can be determined through a collaborative process, or that consensus could be achieved within a reasonable period of time. In a collaborative process, consensus among the parties is desirable for the process to be effective. However, on issues such as an oil price forecast, consensus will be difficult to achieve.

6. In the proposed collaborative process where the Commission would produce an estimate of avoided costs, the Companies presume that the Commission would need to compile and disseminate all necessary information to collaborative members, hold periodic discussions with them to facilitate their understanding of the material, and have meetings with them to attempt to reach consensus on the values to be used to determine the

avoided costs. As the Companies have experienced, the IRP process, can consume a vast amount of time. For example, HECO's IRP-3 process will take an estimated 28 months from its beginning to the time the final report is filed with the Commission. Subsequent regulatory steps, such as discovery and an evidentiary hearing (if one is held) will take many more months.

7. The Commission will need to act as arbiter with respect to disagreements. This could strain the Commission's already limited resources and could delay other equally important proceedings.

8. As stated above, there are significant uncertainties with respect to the determination of avoided costs at the present time.

9. It is not clear when avoided costs would first be determined and how frequently they would be determined. Currently, avoided costs are determined at the time negotiations occur with IPPs.

VI. Penalty based on Claw Back of Incremental Utility Profits

With respect to the sixth proposal, the Companies have the following comments and/or questions:

1. The penalty proposed is said to be based on the cost to society of non-compliance and is said to be derived efficiently from the profit maximizing behavior of the utility.

2. As a threshold matter, the Companies point out that the cost to society is an externality whose value is subjective, difficult to determine and highly controversial.

3. If the goal is to make non-compliance and compliance neutral to the Companies on the basis of profitability, it is useful to investigate the likelihood that non-compliance with a RPS would be more profitable to the Companies than compliance. In light of the higher portion of costs associated with renewable projects which are capital costs, if the premise were true a utility subject to cost of service pricing would be assumed to be more inclined, and not less inclined, to pursue renewable projects with their higher rate base contribution.

4. The Companies view the penalty as proposed under the sixth proposal to be subject to the same legal uncertainty as the penalties discussed above under the third proposal.

VII. Payment Based on Marginal Oil-Fired Multiplier

With respect to the seventh proposal, the Companies have the following comments and/or questions:

1. The proposal appears to contemplate the derivation and application of an externality "adder" to the avoided costs of renewable projects, a portion of which might be captured by the Companies as an incentive to invest in renewable projects.

2. As an externality, the number derived would be subjective, difficult to determine and highly controversial.

3. As an amount paid above and beyond the avoided cost of the renewable project, the Companies question whether any such amount is consistent with the mandate of Act 95.

4. The proposal appears to contemplate the derivation and application of an "adder" to the avoided costs of renewable projects based on estimated macroeconomic benefits of avoided oil importation, a portion of which might be captured by the Companies as an incentive to invest in renewable projects. See also the discussion in Exhibit C, Avoided Costs. [Note: In HECO's Externalities Workbook, HECO provided information that economic impacts are generally not considered externalities. HECO Externalities Workbook, p. 1-5]

5. As an economic multiplier on avoided oil payments, the number derived would be subjective, difficult to determine and highly controversial. See also the discussion in Exhibit G, Multiplier Effect.

   a. The proposed mechanism does not cover all cost factors. The proposed mechanism appears to ignore the macroeconomic multiplier effects of the up-front costs for oil-fired generation and renewable energy resources.
   b. The calculation of the multiplier would depend on the availability of accurate economic data. For example, the fuel purchased by the utility is residual fuel oil - the oil cost does not entirely leave the state economy as a portion stays in Hawaii to pay for such items as refinery labor, storage, shipping, etc. If the utility did not use the residual fuel oil, the refineries would be faced with dealing with residual oil after refining various petroleum products.

6. As an amount paid above and beyond the avoided cost of the renewable project, the Companies question whether any such amount is consistent with the mandate of Act 95.

HAWAII RPS LAW

I. Hawaii Legislation

1. The provisions making up Hawaii's renewable portfolio standards ("RPS") law were enacted by Act 272, 2001 Hawaii Session Laws ("Act 272") and were amended by Act 95, 2004 Hawaii Session Laws ("Act 95").

2. The provisions are codified in HRS Chapter 269 in Sections 269-91 to 269-95, and in HRS Section 196-41.

II. HRS Chapter 269

1. In general, H.R.S. Section 269-92, as amended by Act 95 (2004), provides that each electric utility company that sells electricity for consumption in Hawaii shall establish a renewable portfolio standard of:

(1) 7% of its net electricity sales by December 31, 2003;

(2) 8% of its net electricity sales by December 31, 2005;

(3) 10% of its net electricity sales by December 31, 2010;

(4) 15% of its net electricity sales by December 31, 2015; and

(5) 20% of its net electricity sales by December 31, 2020.

In addition, under Section 269-92, the PUC must determine if an electric utility company is unable to meet the renewable portfolio standards in a cost-effective manner, or as a result of circumstances beyond its control which could not have been reasonably anticipated or ameliorated.[1] If this determination is made, the electric utility company is relieved of

[1] Section 269-94, as amended, provides that any electric utility company not meeting the renewable portfolio standard shall report to the PUC within ninety days following the goal dates established in Section 269-92, and provide an explanation for not meeting the renewable portfolio standard. The PUC has the option to either grant a waiver from the renewable portfolio standard or an extension for meeting the prescribed standard.

responsibility for meeting the renewable portfolio standard for the period of time that it is unable to meet the standard.[2]

2. The definition of "renewable energy" in H.R.S. Section 269-91, as amended in 2004 by Act 95, includes electrical energy produced by wind, solar energy, hydropower, landfill gas, waste to energy, geothermal resources, ocean thermal energy conversion, wave energy, biomass, including municipal solid waste, biofuels, or fuels derived from organic sources, hydrogen fuels derived from renewable energy, or fuel cells where the fuel is derived from renewable sources. "Renewable energy" also includes electrical energy savings brought about by the use of solar and heat pump water heating (which were already included in the definition), as well as by seawater air-conditioning district cooling systems, solar air-conditioning and ice storage, quantifiable energy conservation measures, and use of rejected heat from cogeneration and combined heat and power systems (excluding fossil-fueled qualifying facilities that sell electricity to electric utility companies, and central station power projects).

3. H.R.S. Section 269-95(1), as amended, provides that the PUC must: "By December 31, 2006, develop and implement a utility ratemaking structure which may include but is not limited to performance-based ratemaking, to provide incentives that encourage Hawaii's electric utility companies to use cost-effective renewable energy resources found in Hawaii to meet the renewable portfolio standards established in section 269-92,[3] while allowing for deviation from the standards in the event that the standards cannot be met in a cost-effective manner, or as a result of circumstances beyond the control of the utility which could not have been reasonably anticipated or ameliorated . . . ."

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[2] Under HRS Section 269-91, "cost-effective" means "the ability to produce or purchase electric energy or firm capacity, or both, from renewable energy resources at or below avoided costs."

[3] Under HRS Section 269-94, the PUC also may provide incentives to encourage electric utility companies to exceed their renewable portfolio standards or to meet their renewable portfolio standards ahead of time, or both.

4. H.R.S. Section 269-95(2), as amended, provides that the PUC must: "Gather, review, and analyze empirical data to determine the extent to which any proposed utility ratemaking structure would impact electric utility companies' profit margins, and to ensure that these profit margins do not decrease as a result of the implementation of the proposed ratemaking structure . . . ."

5. Under subparts (3) to (5) of H.R.S. Section 269-95, as amended, the PUC must:

> (3) Contract with the Hawaii natural energy institute of the University of Hawaii to conduct independent studies to be reviewed by a panel of experts, which must include findings and recommendations regarding:
> (A) The capability of Hawaii's electric utility companies to achieve renewable portfolio standards in a cost-effective manner; and
> (B) Projected renewable portfolio standards to be set five and ten years beyond the then current standards;
> (4) Revise the standards based on the best information available at the time if the results of the studies conflict with the renewable portfolio standards established by Section 269-92; and
> (5) Report its findings and revisions to the renewable portfolio standards to the Legislature no later than 20 days before the convening of the regular session of 2009, and every five years thereafter."

III. <u>HRS Section 196-41</u>

1. HRS Section 196-41(a) provides that the Department of Land and Natural Resources ("DLNR") and the Department of Business, Economic Development, and Tourism ("DBEDT") "shall facilitate the private sector's development of renewable energy projects by supporting the private sector's attainment of the renewable portfolio standards in section 269-92. Both departments shall provide meaningful support in areas relevant to the mission and functions of each department as provided in this section, as well as in other areas the directors of each department may deem appropriate."

2. Section 196-41(b) provides that DLNR shall: "(1) Develop and publish a catalog by December 31, 2006, and every five years thereafter, of potential sites for the development of renewable energy; and (2) Work with electric utility companies and with other renewable energy

developers on all applicable planning and permitting processes to expedite the development of renewable energy resources."

3. Section 196-41(c) provides that DBEDT shall: "(1) Develop a program to maximize the use of renewable energy and cost-effective conservation measures by state government agencies; (2) Work with federal agencies to develop as much research, development and demonstration funding, and technical assistance as possible to support Hawaii in its efforts to achieve its renewable portfolio standards; and (3) Biennially, beginning in January 2006, issue a progress report to the governor and legislature."

IV. <u>RPS Legislative History</u>

1. The Hawaii Legislature explicitly considered, but did not adopt, penalty mechanisms as part of the RPS law. In the 2001 and 2004 Hawaii State Legislative sessions, a number of proposed bills related to RPS were introduced and heard in various committees. Some of these proposed bills contained mechanisms penalizing the electric utility for not achieving the RPS goals on a timely basis. During the various hearings before House and Senate Energy and Environment and Commerce and Consumer Protection Committees, testimonies were heard from utilities, government agencies, private business, other organizations and the general public on the pros and cons of a penalty mechanism in the proposed RPS bills. The original bills were either passed as written, modified (committee draft) or held in committee. To this end, a modified RPS bill, that does not include any penalty clauses, was finally agreed upon in a joint conference committee and the Hawaii State Legislature voted and approved the RPS bill.

2. The Governor signed the RPS bill into law in 2001 as Act 272 and in 2004 as Act 95.

Avoided Costs

I. <u>AVOIDED COSTS</u>

As defined in the Commission's avoided cost rules, "avoided costs" means the "incremental or additional costs to an electric utility of electric energy or firm capacity or both which costs the utility would avoid by purchase from the qualifying facility." H.A.R. §6-74-1.

In calculating avoided costs, the HECO Utilities utilize the differential revenue requirements ("DRR") methodology. Under this methodology, a base utility plan and a non-utility generator ("NUG") NUG-in plan are compared. The difference in the utility's costs between the base and NUG-in plans represents the costs that the HECO Utilities can avoid with the non-utility generator alternative. See, e.g., Order No. 15187 (November 25, 1996), Docket No. 94-0079 ("Order No. 15187"), at 8.

If the base plan costs are higher than the NUG-in plan costs, such as when a NUG installs a large increment of firm capacity, the difference between the base and alternate plan costs represents those costs avoided by the utility. Likewise, if additional costs are incurred in the NUG-in plan, which causes the NUG-in costs to be greater than the base plan costs (such as for line losses), this results in a reduction to avoided costs.

The DRR Method of calculating long-term avoided costs has been used in determining the avoided costs for previous power purchase proposals. For example, this methodology was examined extensively by the Commission and the other parties involved in HECO's application for approval of the AES-Barbers Point, Inc. ("AES-BP") and Kalaeloa Partners, L.P. ("Kalaeloa") power purchase contracts in Docket Nos. 6177 and 6378, respectively.

The Commission explained the use of the DRR method as follows in Order No. 15187 (page 8):

> In calculating avoided cost, the differential revenue requirements methodology is applied. Under this methodology, a base utility plan and a QF-in plan . . . are compared. The difference in the utility's costs between the base and QF-in plans represents the costs that HELCO can avoid with the non-utility generator alternative.

The DRR methodology is one of three generally accepted methodologies to determine avoided costs.[1] The DRR methodology is often referred to as the most accurate methodology for determining avoided costs because it is the only methodology that explicitly develops a long-term plan for a base case and an alternate (NUG-in) case and forecasts revenue requirements for each case. The principal strengths of the DRR methodology are that, for each NUG contract it examines, it develops a detailed assessment of the impact of the NUG upon the utility plan and a comprehensive assessment of the cost (revenue requirements) impact of the NUG contract to the utility.

II. PAYMENT RATES ABOVE AVOIDED COSTS

A. FERC Avoided Cost Cap Rulings

The Federal Energy Regulatory Commission ("FERC") has held that jurisdiction over the rates charged by QFs for sales at wholesale (which includes sales to public utilities) is vested in FERC, and that PURPA preempts state statutes or regulations that would require the payment of a rate in excess of avoided cost (determined in accordance with the FERC rules, as implemented by the States) to QFs. (FERC also held that its decision would not have retroactive effect, and that FERC would not entertain requests to invalidate pre-existing contracts where the avoided cost issue could have been raised, but was not.) According to the FERC ruling, state

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[1] The other two avoided cost methodologies are the peaker method and the proxy plant method. The peaker method is a marginal cost approach. It is referred to by several names including the component method and short-run marginal cost. In applying the method, avoided capacity costs are set equal to the cost of a new peaking unit (or lower if there is surplus capacity) and avoided energy costs are determined as system marginal energy costs. The proxy plant method identifies the next unit that would be added by the utility. Both capacity and energy costs are set based upon the cost of the proxy unit.

commissions could require payment rates in excess of avoided costs for entities that are not QFs or public utilities (under the Federal Power Act). See Re Connecticut Light & Power Co., Docket No. EL93-55-000, Order Granting Petition for Declaratory Order (FERC Jan. 11, 1995).

B. Minimum Payment Rates Above Avoided Cost

H.R.S. §269-27.2(c) allowed the PUC to prescribe the rate to be paid to a nonfossil fuel producer, and (as amended in 1985) directed the PUC, in determining the just and reasonable rate to be paid to such a producer, to consider, on a generic basis, the minimum floor a utility should pay, giving consideration not only to the near-term adverse consequences to the ultimate consumers of utility provided electricity, but also to the long-term desirable goal of encouraging, to the greatest extent practicable, the development of alternative sources of energy.

The inclusion of minimum rates in purchased power agreements ("PPAs") sometimes resulted in payment rates in excess of avoided costs. Thus, in Act 95, the Legislature repealed that portion of Section 269-27.2 that required the inclusion of minimum floor rates.

C. Externality Adders To Avoided Costs

The PUC's IRP Framework requires that external costs and benefits be considered in the integrated resource planning process, but does not specify the weight to be given externalities in selecting the utility's preferred integrated resource plan ("IRP Plan"). Re Integrated Resource Planning, Docket No. 7257, Decision and Order No. 13839 (March 31, 1995) at 25.

External costs are direct or indirect costs to or negative impacts on the activities of entities outside the utility. Under the IRP Framework, external costs include "environmental, cultural and general economic costs." In general, societal costs are equal to utility costs plus external costs (less "transfer" payments, which are payments from the utility, such as taxes, to society in general).

FERC's avoided cost cap rulings appear to preclude the payment of an externalities adder to a renewable energy producer. FERC has indicated that, "in setting avoided cost rates, a state may only account for costs which actually would be incurred by utilities," and that a state "may not set avoided costs rates . . . by imposing environmental adders or subtractors that are not based on real costs that would be incurred by utilities." Re Southern California Edison Co., Docket No. EL95-1 6-000, Order on Requests for Reconsideration (F.E.R.C. June 2, 1995).[2]

D. Renewable Energy Bidding Schemes

In 1992, the California Public Utilities Commission ("PUC") included a requirement for a "Green" RFP in its Biennial Resource Plan Update ("BRPU") program. However, in a decision deciding two dockets, FERC held that the 1992 California PUC BRPU program violated PURPA and FERC's implementing regulations, because the California PUC did not consider all sources in reaching its avoided cost determinations. Re Southern California Edison Co., Docket No. EL95-1 6-000, Order on Petition for Enforcement Action Pursuant to Section 210(h) of PURPA (F.E.R.C. Feb. 23, 1995), reconsideration denied, Order on Requests for Reconsideration (June 2, 1995).

According to the decision, the BRPU process had three stages. In the first stage, the utilities filed a resource plan identifying potential resource additions and the California PUC determined what new resources the utilities would add. In the second stage, the California PUC determined the utilities' assumed costs, known as "benchmark prices", for the resource additions, and determined which of the additions could be avoided. In the third stage, QFs were allowed to

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[2] States may choose to provide taxpayer subsidies for renewable energy, not utility avoided cost adders. Rates for QF power that exceeds avoided cost do not violate PURPA if they are offset by a "dollar-for-dollar tax credit, calculated and credited to the utility on a month-by-month basis, that equals the amount by which rates . . . exceeded the utility's avoided cost." Re CGE Fulton. L.L.C, Docket No, EL95-27-001, 70 F.E.R.C. 161,290, 1995 FERC Lexis 404 (F.E.R.C. March 15, 1995), reconsideration denied, 71 F.E.R.C. 61,232, 1995 FERC Lexis 1027 (May 25, 1995).

bid against the utilities' benchmark prices, and the utilities were directed to enter into standard offer contracts with the winning bidders (if bids were received that were below the benchmark prices) at prices equal to the price bid by the second lowest bidder.

In the Southern California Edison ("SCE") case, Docket No. EL95-1 6-000, the deferrable resources identified by the California PUC included two new geothermal plants, a wind farm, and the re-powering of an existing steam plant. The identified deferrable resources ("IDRs") would cost much more than constructing new gas-fired turbines, but the California PUC concluded that the lDRs were economic by imputing "massive" environmental compliance costs to the alternative gas-fired resources. The California PUC, implementing a California statute, also required that one-half of the capacity for three of the four lDRs be reserved solely for renewable bidders. Under the California procedure, winning bidders would be paid an air emissions adder/subtractor based on the difference in projected emissions between the bid-winning QF project and the IDA. SCE claimed that lower-cost alternatives were available for 4.O cents/kwh or less, even though it was required to execute contracts with QFs at initial rates as high as 6.6 cents/kwh. San Diego Gas & Electric Co. ("SDG&E") raised similar claims in Docket No. EL 95-19-000.

In its decision, FERC stated that the QF industry was a developed industry and the need for integration of policy objectives under PURPA and other federal electric regulatory policies was pronounced, particularly given the fact that the electric utility industry is in the midst of the transition to a competitive wholesale power market. QF rates that exceed avoided cost will give QFs an unfair advantage over other market participants (non-QFs), which will hinder the development of competitive markets and hurt ratepayers.

FERC held that the California PUC's method of determining avoided cost was inconsistent with PURPA and FERC's regulations. FERC held that regardless of whether the State regulatory authority determines avoided cost administratively, through competitive bidding, or some combination thereof, it must in its process reflect prices available from all sources able to sell to the utility whose avoided cost is being determined. If the State determines avoided cost by relying on competitive bidding, the bidding cannot be limited to QFs.

At the same time, FERC acknowledged California's ability under its authority over electric utilities subject to its jurisdiction to favor particular generation technologies over others. FERC stated that, under State authority, a State may choose to require a utility to construct generation capacity of a preferred technology or to purchase power from the supplier of a particular type of resource, so long as such action does not result in rates above avoided cost.

III. IRP SET ASIDES

How can a utility take into account the beneficial attributes of renewable resources in determining the price to be paid to producers of renewable resources, or in determining that the utility itself should implement renewable resources, when the standard of cost-effective is avoided cost?

First, it is clear that the utility cannot be expected to simply boost the avoided cost price paid to renewable resource producers by the amount of an "externalities adder."

Second, the utility cannot be expected to "determine" an independent avoided cost for renewable resources simply by conducting a competitive bid limited to renewable resources.

On the other hand, it does appear that the utility can incorporate specific resources, or types of resources, in an IRP Plan, based on the attributes of those resources and the degree to which they help the utility achieve the goals and objectives specified for the IRP Plan.

Neither the FERC rulings, nor Act 95, should preclude the consideration of externalities in the selection of a utility resource plan (which could include renewable resources, or which could form the basis for a higher utility avoided cost determination for purchased power resources, including renewable resources, that provide equivalent externalities benefits). The qualitative consideration of externalities can have an impact in increasing the avoided cost available to renewable resources. For example, HECO did not adopt the least utility-cost plan as its preferred IRP Plan in Docket No. 7257. HECO adopted a somewhat more expensive plan, from a utility-cost standpoint, that included coal-fired generation in order to reduce HECO's dependency on fuel oil. To the extent that a renewable resource can provide equivalent benefits, the renewable resource could receive a price higher than that based on the utilities least utility-cost plan (which might include only oil-fired generation).

Thus, it appears that the utility can establish "set asides" as part of its IRP Plan for resources that will allow the utility to obtain the designated attributes, as long as the set asides do not arbitrarily exclude other resources that would provide the same attributes.

The additional benefit of doing this as part of an IRP process is that the utility can take into consideration all of the factors deemed significant by Act 95, and the PUC can approve or modify the resulting plan. IR mechanisms can be targeted to the specific resources to be acquired.

The mechanisms used to acquire the targeted resources also can be determined in the IRP process, which would include a determination of whether competitive bidding should be used.

Act 95: Renewable Resource and Costs

HECO has comments on the accuracy of some of the cost numbers and statements and the basis or validity of the assumptions. HECO's specific comments by SCP's numbered paragraphs are provided below:

Renewable Energy

<u>Paragraph 107 – Operation</u>

- It should be acknowledged that generating facilities are not interchangeable. Some facilities provide dispatchable, baseload, cycling, and peaking capacity and energy (e.g., fossil-fired plants, geothermal and biomass), while others provide intermittent, non-dispatchable energy (e.g., wind, solar, and ocean wave).
- Only firm renewable energy resources with the same operational characteristics and ability to meet load as the replaced oil-fired generation must be considered. Due to the inability of Hawaii utilities to buy power from other states or utilities and the timeframes to plan, permit, design, and build firm generation resources, Hawaii utilities must use proven, commercial technologies.

<u>Paragraph 111 – Siting</u>

- HECO agrees that siting of new generation on all islands, regardless of technology, remains a challenge.
- HECO also agrees that capital costs in Hawaii are higher than on the mainland.
- Oahu while having about 80 percent of the population, does not have the renewable energy resources that are found on the neighbor islands. Oahu does not have a known geothermal resource, large streams or rivers for hydroelectric plants, sugar mills for biomass energy and class 7 wind regimes.

<u>Table D1 – Capital costs</u>

- The applicability of the costs cited in Table D1 to Hawaii is suspect.
  - Use of Table D-1 should be qualified to indicate applicability to Hawaii and, per EIA, these costs do not account for learning effects and regional multipliers.
  - Costs for wind, biomass, fuel cells, solar thermal, and solar photovoltaics seem low. Hawaii costs are likely to be higher.
  - Wind costs in Hawaii may be higher because of wind project size, site specific cost issues, wind regime assumptions, and other cost impacts.
  - The photovoltaic cost assumption appears to be low. Current photovoltaic costs have increased since solar module demand is high and supply is low.
- It is unclear if the biomass cost in Table D1 is based on biomass waste products or a dedicated biomass crop. Also, the conversion technology is not specified.
  - Current biomass facilities generate electricity using waste biomass products as a fuel feedstock, thus a function of the availability of such biomass waste fuel. Referenced source in Table D1 (EIA, Table 38 notes on-line year for biomass is 2010). According to the Electric Power Research Institute there is no commercial dedicated biomass to electricity facility operating in the U.S.
- It is unclear as to what type of fuel cell is being portrayed in Table D1.
- Geothermal costs in Hawaii may be higher than the costs quoted in Table D1. Referenced source in Table D1 (EIA, Table 38) mentions that geothermal cost and

performance is site specific and this table represents the cost of the least expensive plant that could be built in the Northwest Power Pool region.

- It is unclear at to what type of solar thermal technology (parabolic trough, dish-engine or power tower) is being portrayed in Table D1.

Table D4 – Costs

- Capital and O&M costs for geothermal (Big Island) appear to be low. Assumptions should be provided.
- Assumptions for cost of energy for geothermal project should be provided.
- EI should elaborate on the technology constraints mentioned in the footnote.

Wind

Paragraph 108 – Technology

- The applicability of the levelized energy cost for wind cited by EI ($0.05/kWh) needs to be clarified. This energy cost may not be reflective of wind farms in Hawaii. The assumptions used to derive this energy cost should be disclosed.
- The PUC has established that capacity credit for wind is not warranted. In Docket No. 00-0135 (Apollo Energy Corporation Petition), Decision and Order No. 18568, dated May 30, 2001, the PUC stated, "The commission does not believe that capacity payments for Apollo are warranted."
- Operational issues must be considered when evaluating the "wind project portfolio" concept. The ability of island-based utilities to maintain power quality due to short-term fluctuations of multiple wind farms on the system and the curtailment of wind farms must be considered.
- A key question is: Can an island grid system handle the amount of distributed wind penetration that is needed to achieve the reduction of output variability such that capacity benefits are observed?

Paragraph 115 – Capital costs

- The range in wind cost is due to varying assumptions (wind speeds, size, site conditions, etc.) used by each reference. In general, smaller wind farms may cost more than larger wind farms because of economies of scale and other factors.
- The cost of wind turbines have actually increased recently due to higher steel prices, unfavorable money exchange with the Euro, tight wind turbine manufacturing capacity, and a general rush to install wind projects prior to the *previously* scheduled expiration date of the federal wind production tax credit at the end of 2005.

Table D2 – Projects

- The costs for wind projects seem low.
    - It is recommended that capital and O&M costs for wind projects evaluated in the IRP-3 of HECO, HELCO, and MECO be utilized in the EI analysis.
    - Use of cost ranges to show the low and high cost estimates of the wind farms should be considered.
    - The year that the cost estimates were made, or are applicable to, should be cited.
- EI should qualify Table D2 to indicate that the candidate projects at specific sites may be mutually exclusive (i.e., not all listed wind farms or size options will be built at a particular site).

- It is unclear whether the assumptions for cost of energy (cents per kilowatt-hour) are the same for the GEC and WSB calculations.
- Table D2 notes that some wind sites assume only future costs. It is unknown whether future costs are lower or higher than current cost assumptions used by GEC and WSB.
- EI should note that the Air Force's proposed Kaena Point wind demonstration project encountered local opposition (i.e., cultural, environmental, visual, and other impacts).

<u>Biomass</u>

<u>Paragraph 110 – Technology</u>

- Biomass gasification research and development have stalled since the Maui Paia and Vermont biomass gasifier projects. It is unclear if the U.S. Department of Energy has resurrected this R&D effort again. To HECO's knowledge, limited federal support has been provided to biomass gasification development and there are efforts by southern utilities to conduct "proof-of-concept" testing of pressurized biomass gasification. The coupling of the percentage of fuel cell use in Hawaii in the future will be a function of fuel cost, fuel availability, fuel characteristics and other issues.

<u>Paragraph 119 – Biomass and other renewable technology (geothermal, and hydroelectric)</u>

- The cited cost range of $0.051 to $0.101/kWh for biomass, geothermal, and hydroelectric energy is misleading since the footnote for Table D4 states that "All candidate projects considered by GEC are included only in future scenarios due to current technology constraints.".

<u>Solar</u>

<u>Paragraph 117 – Cost</u>

- The energy cost for parabolic trough systems appears to be low ($0.077/kWh). The basis and reference for the energy cost estimates for parabolic trough systems should be provided.
- A 1992 study conducted by Dave Kearney & Associates states that the solar resource applicable to solar electric generating plants in Hawaii is approximately 25-30 percent lower than the Mojave Desert on an annual basis.
    - Lower solar insolation resources would result in a commensurately higher cost of solar energy production on a $ per kWh basis.
    - It should be noted that efficient operation of solar thermal electric systems, such as parabolic trough systems, require high direct normal insolation (i.e., the sunlight that is not scattered by the earth's atmosphere). Photovoltaic systems, however, can utilize the total or global insolation resource, which includes both direct normal insolation and diffuse insolation (i.e., the sunlight that is scattered by the earth's atmosphere).
    - Current and planned solar thermal electric power plants in the U.S. are located in the southwest due to the high direct normal insolation resources in this region.

- It is unclear if the future solar thermal facilities being cited are solar only, hybrid or include storage.

Table D3 - Cost

- The photovoltaic cost assumptions appear to be low.
  - Current photovoltaic costs have increased since solar modules demand is high and supply is low.
- The solar thermal cost appears to be low.
  - It is unclear if future solar thermal facilities are solar only, hybrid, or includes storage.
  - The basis for the parabolic trough cost estimates should be provided, including the source and specification of capital and O&M costs.

Competitive Bidding

In their Final Statement of Position filed August 11, 2005, in Docket No. 03-0372, the HECO Companies indicated that they can support competitive bidding for certain forms of new generation, but only if it is structured in such a fashion that the potential benefits can be realized, and the potential disadvantages can be mitigated or eliminated, and only if appropriate exceptions are recognized.

Percentage of Purchased Power

The percentage of firm capacity provided by Independent Power Producers ("IPPs") on HECO's system has increased from 0% prior to 1990 to approximately 25% today, and is expected to increase to about 26% once Amendment Nos. 5 and 6 to the Kalaeloa amended purchase power agreement ("PPA") become effective. The percentage of HECO's baseloaded capacity provided by IPP's is even higher – about 35% assuming Kalaeloa provides 209 MW. The percentage of power provided by IPPs on Hawaii is even greater.

	2004 IPP Capacity as a Percent of Firm Capacity	2004 IPP Generation as a Percent of Total Net-to-System Generation	2006 IPP Capacity as a Percent of Firm Capacity	2006 IPP Generation as a Percent of Total Net-to-System Generation
Oahu	25%	39%	26%	42%
Maui	6%	7%	6%	16%
Hawaii	37%	65%	33%	64%

Integration of Purchased Power into Utility Systems

While a generating resource generally may be installed under either a utility or an IPP ownership structure, the utility's control over the resource differs substantially depending on whether the utility owns the resource, or obtains the resource under a PPA. The presence of a

PPA between the utility and an IPP does not provide the utility with as much operating flexibility as the utility has with its own units. While the PPA can specify operating conditions favorable to the utility (such as coordination of maintenance, dispatchability, etc.), the utility generally has less control over plant maintenance practices, operational considerations, fuel conversion opportunities, and environmental enhancements. In contrast, the utility has such operating flexibility with its own units.[1]

Utilities have the obligation to serve their customers while IPPs who supply capacity and energy to the utilities under PPAs may be obligated to provide to the utility only those items and services, or to perform only those duties, that are covered by provisions in the PPA. At times, this can constrain the utility's operating flexibility. As a result, a utility has much more flexibility to adjust to changed circumstances if it owns and operates it own units, than if it purchases power under long-term PPAs, because PPAs cannot be drafted to provide for all future contingencies and changed circumstances.

Under state energy policy, the utility's focus is first on acquiring new renewable energy generation. That means that the competitive bidding process, if any, should facilitate the acquisition of renewable energy generation, and that other types of generation added to the system should accommodate the introduction of more renewable energy generation to the utility's system. It is expected that there will be opportunities in the future to purchase additional renewables on a firm capacity basis (for example, if an additional waste-to-energy capacity is added at Campbell Industrial Park), and if the percentage of purchased power is increased, it should be accompanied with the benefit of adding renewables.

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[1] HECO, for example, has been able to manage the integration of the Kalaeloa, AES and H-Power facilities into its system, but there is substantial uncertainty as to how much more firm power could be purchased without substantial negative impact on HECO's operational flexibility.

The most successful IPP projects have been those where the utility was able to take advantage of a resource that could be developed by a third-party with expertise in developing that resource. Examples would include PGV's geothermal facility, H-Power's waste-to-energy facility, Kalaeloa's facility, which was only the second combined cycle facility to be fired on low sulfur fuel oil ("LSFO") (and which made the continued participation of the manufacturer of the facility an essential element of the power purchase arrangement), and AES Hawaii, which utilizes a circulating fluidized bed technology pioneered by AES. This consideration does not necessarily apply to future non-renewable energy projects.

<u>Competitive Bidding and Integrated Resource Planning</u>

The competitive bidding process should be integrated with the integrated resource planning ("IRP") process.

The IRP Plan can continue to be developed using the current process followed by the HECO Companies. In this case, the role of the IRP Plan should be to identify the preliminary "preferred" resource plan, define capacity and energy requirements, the timing of need, any preferred technologies, and potentially any other preferred attributes. The IRP Plan can also be used to identify any preferences or criteria for resource selection and can be used to determine avoided costs.

In this model, the role of the RFP would include the solicitation and evaluation of resource options to meet the capacity and energy needs identified in the preliminary preferred resource plan. The RFP can be used to solicit bids for either a block of resources as defined in the IRP Plan or for the next required resource identified in the IRP Plan. Bidders would be allowed to submit proposals for any variety of resource types and sizes. The utility also would have the right to submit proposals for resources that may differ from the preferred resource type included in the preliminary resource plan. The bids received in response to the RFP would be evaluated relative to one another and/or to the avoided costs of the generic resource identified in the IRP Plan or to the utility self-build project. The IRP Plan would establish the parameters for the RFP. After the bids are evaluated and the preferred resource selected, the utility would then build the resource (if a self-build system is selected), or negotiate a turnkey contract or PPA with the winning bidder (if a turnkey or PPA option is selected). The utility would essentially complete its preferred resource plan after the bids are received -- the final bid(s) selected would be part of the final IRP Plan.

Competitive Bidding and Avoided Cost

The competitive bidding process generally should supercede the process of negotiating PPAs under the PUC's "Standards for Small Power Production and Cogeneration", which were adopted pursuant to the Public Utility Regulatory Policies Act of 1948 ("PURPA"), and the rules promulgated by the Federal Regulatory Energy Commission under PURPA, and H.R.S. § 269-27.2.

IRP Framework

The IRP Framework (revised May 22, 1992) was adopted by the Hawaii Public Utilities Commission (the "Commission") by Decision and Order No. 11630 (May 22, 1992) ("D&O 11680") in Docket No. 6617, amending and reissuing the IRP Framework adopted in Decision and Order No. 11523 (March 12, 1992).

The IRP Framework provides that the goal of integrated resource planning is the identification of the resources or the mix of resources for meeting near and long-term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost. Among the governing principles included in the IRP framework are statements that IRP Plans (1) shall comport with state and county environmental, health and safety laws and formally adopted state and county plans, (2) shall be developed upon consideration and analyses of the costs, effectiveness, and benefits of all appropriate, available, and feasible supply-side and demand-side options, and (3) shall give consideration to the plans' impacts upon the utility's consumers, the environment, culture, community lifestyles, the State's economy, and society. IRP Framework II.A. and II.B. 2, 3, 4.

The IRP Framework requires utilities to consider all feasible supply-side (including renewables) resources and demand-side resources appropriate to Hawaii, and provides specific goals and objectives for utility resource planning. (The IRP process is broad enough to allow consideration of specific, targeted objectives, such as a specified reduction in the use of imported oil, IRP Framework, III.B.2), and consideration of alternative integrated resource plans that include a greater percentage of renewable resources. The IRP process also takes into consideration utility operational and system reliability considerations.

MULTIPLIER EFFECT

The multiplier effect attempts to take into account the "induced" effect on the economy of the direct economic impacts of economic activities. All economic impacts of alternative resources should be considered.[1] Oil-fired power plants do not burn crude oil – they largely burn residual fuel oil that is left after refinery processes produce transportation fuels (gasoline and jet fuel). The induced economic impacts of burning residual fuel oil produced by the refineries is different than the impact of importing oil solely for utility use.

In addition, all generating facilities are capital intensive, and renewable facilities may be more capital intensive than fossil-fueled facilities. What is the source of and the induced economic impact of the capital resources required? Also, there is very little manufacturing activity in Hawaii. The dollars spent on purchasing equipment for generating facilities (whether fossil-fuel facilities or wind facilities) flow out of state, while the dollars for constructing, operating and maintaining facilities tend to stay in state.

Any analysis of the multiplier effect requires hundreds of assumptions related to resource availability, costs, economic impacts and other factors. There are numerous market dynamics that could dramatically alter the results of any analysis.

As part of its IRP-2 and IRP-3 processes, HECO provided studies by (1) NERA – "Impacts on the Hawaii Economy of Alternative Resource Plan for Oahu" (December 1997), and (2) UHERO – "Integrated Resource Planning Macroeconomics Impact Study" (March 3, 2005).

The NERA Study examined the economic impacts on Oahu and the Neighbor Islands of four alternative HECO resource plans:

- Base Plan – the "least cost" resource plan (2 diesel-fired, 317 MW combined cycle units;
- Biomass Unit Plan – Base Plan plus a 25 MW biomass unit and deferring construction of the other units.
- Wind Unit Plan – Base Plan plus a 20 MW wind farm.
- Minimize Oil Plan – Two (2) wind farms, 3 coal-fired units, 1 diesel-fired combustion turbine, and 1 biomass unit.

The conclusions reached in the NERA Study included:

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[1] The PUC's IRP Framework requires that external costs and benefits be considered in the integrated resource planning process. External costs are direct or indirect costs to or negative impacts on the activities of entities outside the utility. Under the IRP Framework, external costs include "environmental, cultural and general economic costs."

Although it is not clear from the definition of externalities in the IRP Framework, economists recognize that there is a distinct difference between the economic impacts of alternate technologies – such as oil, coal, municipal waste, geothermal, wind and biomass – and externalities as traditionally defined. (In general, economists define externalities as all of the costs and benefits of a transaction which are not borne or received through the price system by producers or consumers in the course of a transaction.) This is addressed in the HECO Utilities' Hawaii Externalities Workbook (July 1997), filed July 22, 1997 in IRP Docket Nos. 95-0347 (HECO), 7258 (MECO) and 7259 (HELCO).

- All three alternative HECO resource plans evaluated had negative impacts on the Oahu and Hawaii economies when compared to the Base Plan. The exception was a positive impact in employment on Oahu under the Biomass Unit Plan, which led to a net gain due to a relatively large increase in farm employment. However, the Biomass Unit Plan resulted in an overall reduction in personal income on Oahu, reflecting that farm jobs gained are relatively lower-paying. Similarly, the neighbor islands, experienced negative impacts under all three alternative HECO resource plans.

- Negative impacts were substantially greater for the Minimize Oil Plan than for the two other alternative plans. The larger negative impacts reflected the greater commitment to more expensive alternative power options under the Minimize Oil Plan.

- Sensitivity results for the Minimize Oil Plan – showing maximum potential gain from modifying HECO resources to avoid adverse effects of an oil price spike – remained uniformly negative for employment, population, gross regional product, and personal income. Negative impacts of the Minimize Oil Plan relative to the Base Plan tended to increase if all economic effects of an oil price spike on the Hawaii economy were taken into account.

- Base Plan was most beneficial to the Hawaii economy. Regardless of the fact that the impacts are small as a percentage of the overall state economy, the study showed that the alternative plans had consistently negative impacts relative to the Base Plan.

- There was no reason to choose one of the alternative resource plans over the Base Plan from the perspective of the health of the Hawaii economy.

The UHERO Study conducted a macroeconomic analysis of six alternative long-range integrated resource plans for Oahu:

- Least Cost Plan
- 20% Renewable Energy on Oahu by 2020
- Maximize Renewable Energy
- HECO RPS with Contributions from HELCO/MECO
- Maximize Fuel Diversity
- Combined Plan

The conclusions in the UHERO Study included:

- Real gross state products (GSP) are very similar across all integrated resource plans analyzed. Real household expenditures are also similar across all integrated resource plans. Differences in plans are less than +/- 0.1% of real GSP and real household expenditures. Thus, macroeconomic differences between the plans are negligible.

- Construction expenditures expand real GSP in the years when projects are undertaken. These construction expenditures also raise electricity costs for producers and households. Thus, the standard of living does not necessarily increase when real GSP increases.

- As petroleum-based fuel import prices increase, the cost of providing petroleum-based electricity also rises in a manner that lowers real GSP and real household expenditures. Greater inclusion of non-petroleum electricity generation results in a smaller impact of petroleum price increases on the economy.