Proposals for Implementing Renewable Portfolio Standards in Hawaii

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Executive Summary

Legislative Mandate

The Hawaii Public Utilities Commission ("Commission") is required to develop and implement, by December 31, 2006, an electric utility ratemaking structure that provides incentives encouraging electric utilities in Hawaii to use cost-effective renewable energy resources in order to meet the established renewable portfolio standards ("RPS"). The ratemaking structure allows for deviations from the RPS if it cannot be achieved in a cost-effective manner, or if it cannot be achieved as a result of circumstances beyond the control of the utility. The ratemaking structure may include performance-based ratemaking ("PBR"), which is a form of incentive regulation ("IR") typically providing rewards or penalties upon meeting or falling short of performance standards.

The RPS statute of Hawaii was originally enacted in 2001 as Act 272, and modified in 2004 as Act 95. Under the RPS of Hawaii, the RPS is defined as the percentage of electrical energy sales that is represented by renewable energy. The share of renewable energy resources is required by law to increase from 8% in 2005 to 10% in 2010, 15% in 2015, and 20% in 2020. An electric utility company and its affiliates may combine their renewable energy portfolios in order to meet the RPS. The Commission may provide incentives for electric utilities to exceed their RPS, to meet their RPS ahead of time, or both. One of the most prominent aspects of Hawaii's RPS is the provision that the rate paid to a renewable energy generator is capped at 100% of avoided cost. One implication is that, by design, the RPS program in Hawaii is unlikely to be a cause of an increase in retail rates in future.

Under the RPS of Hawaii, the Commission is to determine the impact of any proposed utility ratemaking structure on the profit margins of electric utilities, and to ensure that such profit margins do not decrease as a result of implementing the proposed utility ratemaking structure. Moreover, the Commission is required to contract with the University of Hawaii in order to conduct independent studies on the capability of Hawaii's electric utilities to achieve the RPS in a cost-effective manner, and on a variety of other factors potentially affecting RPS implementation, including those deemed appropriate by the Commission. The Commission is to report its findings on, and revisions to, the RPS to the legislature no later than 20 days before the convening of the regular session of 2009, and every five years thereafter.

At the moment, all electric utilities in Hawaii appear to have satisfied the RPS of 7% of net electricity sales by December 31, 2003. The share of generation from non-fossil fuel energy and quantifiable energy conservation without solar water heating in total sales, for the year ended December 31, 2004, is 9% for the Hawaiian Electric Company, Inc. ("HECO"), 28% for the Hawaii Electric Light Company, Inc. ("HELCO"), and 12% for the Maui Electric Company, Limited ("MECO"). The share of net renewable generation and conserved energy in total sales, for the year ended December 31, 2004, is 13.2% for the Kauai Island Utility Cooperative ("KIUC").

Economists Incorporated (http://www.ei.com), an economics consulting firm with offices in Washington D.C. and the San Francisco Bay Area, provides assistance to the Commission in developing a plan to formulate, through a collaborative process, electric utility ratemaking structures as required by its legislative mandate. The conclusions emerging from this process are likely to form the basis of rules implementing a ratemaking structure that could be adopted in a conventional rulemaking process. Such formally adopted rules to implement the RPS may be used by the Commission pursuant to its legislative requirements.

Collaborative Workshops and Objectives of this Paper

The Commission is organizing three two-day collaborative workshops to explore how to develop and implement a ratemaking structure that encourages the use of renewable energy by utilities. The Commission on November 22-23, 2004 held the first set of workshops in order to gather comments and suggestions on the Commission's planned methodology. An Initial Concept Paper, published by the Commission on November 1, 2004 and used as a starting point for discussions during the first workshop, summarized the Commission's planned methodology in fulfilling its legislative mandate. The Commission has scheduled a second workshop for August 2005.

The objectives of this paper are to survey and analyze the design and implementation of various RPS programs in the U.S., to examine potential alternative renewable energy resources in Hawaii, and to identify proposed or potential ratemaking structures and incentives consisting of candidate RPS components and IR mechanisms for implementing Hawaii's RPS. This paper is intended to serve as a starting point of discussions for the second workshop during which the following issues may be addressed: (a) certain RPS programs from other states for possible use in developing in Hawaii a ratemaking structure that encourages the use of renewable energy; (b) potential renewable energy resources as candidate investment projects in Hawaii; and (c) how proposed ratemaking structures and IR mechanisms can be used as components of ratemaking structures and incentives to implement the Hawaii RPS.

RPS in the U.S.

The 22 states that have statewide renewable resource initiatives in the form of either RPS, RPS-style policies, or RPS/ Set Aside ("SA") policies are Arizona, California, Colorado, Connecticut, Hawaii, Illinois, Iowa, Maine, Maryland, Massachusetts, Minnesota, Montana, Nevada, New Jersey, New Mexico, New York, Pennsylvania, Rhode Island, Texas, Vermont, Washington D.C., and Wisconsin. Under an RPS program or RPS-style policy, a certain percentage of current or new generation capacity (in MW), energy sales (in MWh), or energy growth has to be obtained from renewable energy sources. A RPS/SA policy commonly refers to a requirement to include a certain amount of renewable resources capacity in new installations. Although RPS programs in several states use cost recovery mechanisms that have strong IR influences, the RPS of Hawaii, apart from the ones in Colorado and Vermont, expressly advocates the use of alternative regulatory regimes, such as PBR, in the context of RPS implementation.

The three most common IR mechanisms used in the states with RPS are renewable energy credit ("REC") trading, alternative compliance payments or fees, and penalties. Under a REC trading system, a utility may purchase RECs in order to meet some or all of its RPS requirements. Under a system of alternative compliance fees, a utility can meet the RPS through the payment of fees to a renewable energy development fund. Under a system of penalties, a utility is charged a fine for energy generation that falls short of the RPS. Massachusetts and Rhode Island have REC trading, compliance fees, and penalties. Connecticut, Maryland, Pennsylvania, Vermont, and Washington D.C. have only REC trading and compliance fees. Maine, Montana, Nevada, New Jersey, New Mexico, Texas, and Wisconsin have only REC trading and penalties. Arizona, Colorado, and Minnesota have only REC trading, and California has only penalties. Illinois, Iowa, and New York do not have REC trading, compliance fees, or penalties.

Most states adopting an IR mechanism for RPS implementation create a REC trading mechanism. Most states use more than one IR mechanism. Quite importantly, most states are in still the process of RPS implementation, and their success in providing incentives to meet the RPS, as yet, cannot be fully evaluated. A first step in considering candidate IR mechanisms in the context of RPS implementation in Hawaii is to identify each mechanism's underlying requirements in terms of its legislative mandate or authority, and its relationship to the characteristics of the Hawaii power sector.

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. In allowing the usage of an IR mechanism, an RPS legislative mandate can be characterized in terms of the definition of the policy targets and the authority to institute and operate the IR mechanism. 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.

Not all IR mechanisms require a flexible regime, but a flexible regime is a necessary condition for the use of a REC trading mechanism or compliance fee system. A REC trading mechanism, in essence, allows an electricity supplier to achieve its RPS requirement through the purchase of RECs, which may have been produced out-of-state or carried over from earlier years with excess compliance. A flexible regime also makes compliance possible through the payment of compliance fees. In both a REC trading mechanism and a compliance fee system, the IR mechanism provides financial incentives to encourage renewable energy investments, but annual actual generation or procurement of renewable energy may not correspond to the annual RPS target.

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. A central feature of all three IR mechanisms is the introduction of financial incentives supporting investments in renewable power generation. However, not all three IR mechanisms require the regulator to collect or allocate funds. A REC trading mechanism relies on a market to set REC prices and to allocate resources of electricity suppliers or renewable energy developers. By contrast, a fee or penalty mechanism relies on the regulator (a) to determine the size of the levy it collects, either through a fee or a penalty; (b) to decide the manner of allocating the funds gathered from fee collections for investments in renewable energy generation projects; and (c) to identify the *bona fide* parties accessing the funds.

In addition to the necessary legislative backing, 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. In a restructured power market, independent power merchandisers compete with utilities in serving retail customers, and generation assets are typically in separate companies. An IR mechanism providing an incentive that encourages investments in renewable energy projects may have to be applied to different entities that, in various combinations, have generation assets, serve retail load, or are tasked with achieving the RPS requirement. Moreover, one common characteristic of all states in which REC trading markets have been adopted to date is that they are all continental states. As a consequence, they constitute an integrated territory enabling the transmission of energy within the state, and, if they are contiguous states, they can potentially create regional multi-state REC markets consisting of several states. The creation of larger markets is significant because, in a well functioning market, a large number of buyers and sellers enhances the prospects of satisfying demand at competitive prices.

An important component of RPS implementation is the definition of credible targets and strict enforcement. The arbitrary granting of waivers or exemptions from penalties is likely to undermine the success of RPS implementation. However, a provision aimed at meeting the cost-effectiveness requirement grants exemptions to deviations from RPS targets, and does not imply weak enforcement.

Renewable Energy Resources in Hawaii

The cost of traditional electric power generation has increased significantly in recent years. The cost of energy of a pulverized coal plant is \$0.037/kWh, and a gas combined cycle plant, \$0.035/kWh. Assuming high gas prices, the levelized cost of energy from coal is between \$0.033/kWh and \$0.041/kWh, and that from gas, between \$0.035/kWh and \$0.045/kWh. The cost of many renewable energy sources has declined. Wind technology is considered one of the most viable renewable energy resources in view of improvements in reliability and performance in recent decades. Nationwide, the levelized cost of wind energy is currently \$0.05/kWh. Innovation has led to substantial cost reductions in solar energy over the past several years, and developments in nanotechnology and manufacturing efficiencies are expected to increase significantly the use of solar energy. In Hawaii, the cost of energy of candidate wind projects is between \$0.043/kWh and \$0.078/kWh; candidate parabolic trough system projects, around \$0.077/kWh; candidate fixed photovoltaic systems, more than \$0.20/kWh; and candidate biomass, geothermal, and hydroelectric energy projects, from \$0.051/kWh to \$0.101/kWh.

Although less than 10% of Hawaii's generation and plant capacity utilizes renewable energy, the state currently has a wide range of renewable energy resources, such as biomass, geothermal, hydro, wind, and solar. Data and information assembled through previous research may be used as a starting point for identifying key operational and financial features, such as location, cost estimates, and performance attributes, of candidate projects in Hawaii. Moreover, archetypical renewable projects may be included in the collection of candidate projects. The candidate projects potentially located in Hawaii are to be used in the planned simulations of power production in Hawaii.

The planned production simulations can be used to evaluate candidate electric utility ratemaking structures and IR components. The use of candidate projects in this evaluation does not constitute an endorsement or rejection of specific technologies, plant sizes, locations, years of entry, or other project characteristics, and is not intended to replace or supercede the IRP process.

Potential Components for RPS Implementation in Hawaii

Potential RPS ratemaking structures are subject to further review in workshops and on an on-going basis. The Commission, through the formulation of electric utility ratemaking structures, may pursue several goals in the implementation of Act 95. Market incentives could be provided to bring prices close to costs, reduce costs to their lowest possible level for a given output, and encourage prudent energy usage. Act 95 may be implemented in a flexible manner, to the extent allowed by law. The pace and scope of RPS implementation, either increasing or decreasing the percentage, or advancing or pushing back the compliance year, as technological change occurs or as market participants respond, could be adjusted to the extent the achievement of the RPS, as provided in Act 95, is cost effective. The development of renewable energy technologies may be promoted through the pressures of market forces and regulatory policy. The profit motive of utilities may be harnessed to achieve the RPS through the establishment of a market environment that attracts capital for utility investments and allows utility owners to earn competitive returns on their investment. The exercise of market power potentially causing uneconomic monetary transfers from customers to utility owners may have to be mitigated.

The Commission may consider several components of RPS implementation. The RPS may be treated as mandatory, subject to (a) the satisfaction of the RPS in a cost-effective manner and (b) events or matters beyond the utility's control. A long-term perspective may be taken in implementing the RPS. Periodic reviews of RPS implementation may be held. The broad definition of renewable energy resources specified under the RPS law may be used. The RPS may be integrated with other proceedings pending before the Commission, such as IRP proceedings, rate cases, and others.

Thus far, seven candidate IR mechanisms have been identified and may be used as inputs to the RPS implementation plan of Hawaii. The first three, a REC trading system, alternative compliance fees, and penalties, are gathered from other RPS programs, and the last four, which are specially developed for consideration in Hawaii, are 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.

The first candidate IR mechanism is a REC trading system. Under this mechanism, an electricity supplier may purchase RECs in order to meet some or all of its RPS requirements. One REC is typically equivalent to one MWh of electricity generated from a renewable resource. 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.

The second candidate IR mechanism is the payment of alternative compliance fees. Utilities can meet the RPS through the payment of fees to a renewable energy development fund. The fee may be established on a per kWh basis. The fund may be earmarked to support investments in renewable energy projects, and specific rules may be formulated to identify both eligible projects and *bona fide* users of the fund, such as renewable energy developers seeking to invest in power generation in Hawaii. To serve its load under the RPS requirement, a utility has a choice between acquiring renewable energy generation and paying the fees. It therefore has an incentive to select the cheaper of two options: the cost of the renewable energy acquisition, or the sum of the fees and the cost of replacement non-renewable energy required to serve its load under the RPS requirement. As a result, utilities that can acquire renewable energy in the cheapest way, relative to the fees and their cost of replacement energy, are encouraged to do so.

The third candidate IR mechanism is a system of penalties. Utilities are charged a fine for energy generation that falls short of the RPS. The fine may be established on a per kWh basis. To serve its load under the RPS requirement, a utility has a choice between acquiring renewable energy generation and paying the fine. It therefore has an incentive to select the cheaper of two options: the cost of the renewable energy acquisition, or the sum of the fine and the cost of replacement energy required to serve its load under the RPS requirement. As a result, utilities that can acquire renewable energy in the cheapest way, relative to the fines and their cost of replacement energy, are encouraged to do so.

The fourth candidate IR mechanism calls for the utility to provide an estimate of the avoided cost of its generation mix. In each of the Hawaiian islands and over an adequate time horizon, the avoided cost estimate provided by the utility is the price at which a renewable energy resource, whether its own 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. The avoided cost calculation allows for all types of generation technologies. The methodology for calculating avoided cost can be determined from an avoided cost docket currently on-going in the Commission, or from the current approaches used by utilities in recent submissions to the Commission.

The fifth candidate IR mechanism calls for the Commission to produce, through a collaborative process, an estimate of avoided cost without the RPS. The Commission's avoided cost estimate becomes a benchmark for comparing the utility's cost of acquiring renewable energy resources. If the Commission's avoided cost estimate exceeds the renewable energy resource cost, then the utility is allowed to recover 50%, or some reasonable share, of the difference from ratepayers. The renewable energy resource may be installed through the additional cost-recovery until the RPS is satisfied. If the Commission's avoided cost estimate is less than the renewable energy resource cost, then the power plant associated with the Commission's avoided cost estimate, rather than the renewable energy resource, would be installed. The Commission may grant a temporary waiver to a utility that is unable to satisfy the RPS cost-effectively.

The sixth candidate IR mechanism calls for a dollar penalty. The dollar penalty has to be set at an efficient level. The efficient penalty for a utility is the cost to society of its not achieving the RPS. A penalty that significantly exceeds compliance costs but has a weak link to the efficient penalty may unwittingly induce inefficient utility behavior. One possible measure of the penalty is the incremental benefit to the utility of violating the RPS. The penalty, therefore, is derived from the revealed profit-maximizing behavior of the utilities, and may vary across utilities and over time. A penalty that is excessively large or exceedingly small relative to the level required to alter a utility's profit-maximizing behavior may result in either over- or under-deterrence, which are both costly to society. 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. The penalty could be adjusted until compliance is in the utility's best interest.

Finally, the seventh candidate IR mechanism is based on the idea that the non-adoption of renewable energy imposes additional economic costs. One key assumption is that each MWh of renewable energy displaces one MWh of the marginal technology, oil-fired generation. Given that about 80% of the power generation capacity in Hawaii is fueled by oil, it is likely that the marginal unit displaced by a renewable resource would be oil. Another key assumption is that the marginal unit displacement yields Hawaii an extra saving estimated as the price of imported oil. The oil that a renewable energy resource has displaced is likely to be imported, and the cash saved from the avoidance of the importation would remain in Hawaii. The saving feeds into the Hawaii economy and creates further rounds of spending. The cumulative impact on Hawaii of the initial saving is called a multiplier effect, and could be calculated as the product of the oil price and a multiplier. An independent analyst, such as a macroeconomist at the University of Hawaii, or the macroeconomics literature, could provide an estimate of the multiplier in Hawaii.

Under the seventh candidate IR mechanism, the utility is allowed to recover from ratepayers both the renewable energy resource cost and the payment defined as 50%, or some reasonable share, of the incremental benefit due to the multiplier effect. If, however, 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 therefore no payment is provided.

Recommendations

The seven candidate IR mechanisms should be reviewed in terms of the definition of the RPS target, the Commission's powers to levy a fee and allocate the proceeds, Hawaii's size, location, and proximity to other states, and the status of power sector deregulation in Hawaii.

The first candidate IR mechanism is the establishment of a REC trading system. The definition of the RPS target in terms of RECs adds flexibility to compliance. In particular, REC trading allows flexible RPS compliance in Hawaii through the carry over of excessive or insufficient compliance from one year to another. In principle, REC trading can be implemented in Hawaii because it does not require a deregulated power market. It does not require the Commission to have levy powers, and relies on the REC market to set REC prices. And it does not require the Commission to have allocation powers, and relies on the REC market to allocate resources. However, REC trading could have twin risks associated with Hawaii's size and location. Firstly, Hawaii is a small state, and the small size could limit the number of RECs available for trade. Secondly, Hawaii is a non-contiguous state, and the tendency of concentrating renewable energy generation in some islands may be worsened. The favorable consequences expected from the features of a REC trading market could offset any unfavorable consequences possibly from the twin risks mentioned above. The Commission is advised to consider a REC trading market for further assessment.

The second candidate IR mechanism is the establishment of a compliance fee system. A compliance fee system allows flexible RPS compliance in Hawaii through a combination of compliance fee payment and actual renewable energy generation or REC equivalents. Moreover, it has little to do with the size of Hawaii, its location, or its proximity to other states, and does not require a deregulated power market. However, a compliance fee system requires the Commission to have levy powers for setting the compliance fee at a level that would provide sufficient incentives to encourage renewable energy generation. It also requires the Commission to have allocation powers for collecting fees, creating a fund, and investing. The positive features of a compliance fee system may be worth the potential effort for the Commission to acquire levy and allocation powers, if it does not possess such powers under Act 95. The Commission is advised to consider a compliance fee system for further assessment.

The third candidate IR mechanism is the establishment of a penalty system aimed at deterring non-compliance, and the sixth candidate IR mechanism, the claw back of incremental utility profit, may be interpreted as a specific approach to the calculation of the optimal penalty level. A penalty system does not require the Commission to have allocation powers for creating a fund from them, and investing. Moreover, it has little to do with the size of Hawaii, its location, or its proximity to other states, and does not require a deregulated power market. However, a penalty system does not allow flexible RPS compliance in Hawaii. The payment of a penalty does not amount to compliance, especially if inadequate compliance can be carried over from one year to another. Moreover, a penalty system requires the Commission to have levy powers for setting the penalty at a level that would provide sufficient incentives encouraging renewable energy generation.

The design of optimal penalties should account for their effects on a utility's conduct and their possible interaction with other incentive mechanisms, such as compliance fees. Moreover, an optimal penalty should be set at the level needed to accomplish the deterrent effect that it is supposed to achieve. The sixth candidate mechanism proposes an optimal penalty design based on the principle that the gain from compliance exceeds the gain from violation. In general, the favorable consequences expected from the features of an adequately designed penalty system could offset any unfavorable consequences possibly from the costs of inflexible compliance and the acquisition of levy powers for the Commission. The Commission is advised to consider an optimal penalty system for further assessment.

The fourth and fifth candidate IR mechanisms provide financial incentives for utilities to find the most cost effective approach to RPS compliance. The fourth and fifth candidate IR mechanisms allow flexible RPS compliance in Hawaii. They do not require the Commission to have levy powers; instead, they rely on the utility's response to the mechanisms in determining the level of the financial incentive, and work within the existing regulatory structure in providing a positive or negative financial incentive. They do not require the Commission to have allocation powers; instead, they rely on the utility to allocate its own resources. They have little to do with the size of Hawaii, its location, or its proximity to other states. And they do not require a deregulated power market.

However, under the fourth and fifth candidate IR mechanisms, financial incentives for the provision of cheaper renewable energy come at the expense of potential cost savings that could be passed along to consumers. An optimal incentive design would account for this trade-off. In general, the favorable consequences expected from the fourth and fifth candidate IR mechanisms seem to be substantial and worthy of consideration. The Commission is advised to consider the fourth and fifth candidate IR mechanisms, in which a utility receives its own avoided cost or a difference share, for further assessment.

The seventh candidate IR mechanism proposes to promote the introduction of renewable energy through financial incentives that take into account the broader economic costs of not adopting renewable energy in Hawaii. The seventh candidate IR mechanism allows flexible RPS compliance in Hawaii. It does not require the Commission to have levy powers; instead, it relies on observable variables in determining the level of the financial incentive, and works within the existing regulatory structure in providing a positive or negative financial incentive. It does not require the Commission to have allocation powers; instead, it relies on the utility to allocate its own resources. It has little to do with the size of Hawaii, its location, or its proximity to other states. And it does not require a deregulated power market. Thus, the favorable consequences expected from the seventh candidate IR mechanism seem to be substantial and worthy of consideration. The Commission is advised to consider the seventh candidate IR mechanisms providing payments based on the multiplier concept for further assessment.

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I. Introduction

A. The Legislative Mandate of the Hawaii Public Utilities Commission

1. The Hawaii Public Utilities Commission ("Commission") is required to develop and implement, by December 31, 2006, an electric utility ratemaking structure that provides incentives to encourage electric utilities in Hawaii to use cost-effective renewable energy resources to meet the established renewable portfolio standards ("RPS").[1] The ratemaking structure should allow for deviations from the RPS if the standards cannot be achieved in a cost-effective[2] manner, or if the standards cannot be achieved as a result of circumstances beyond the control of the utility. The ratemaking structure may include performance-based ratemaking ("PBR"), which is a form of incentive regulation ("IR") typically providing a system of rewards or penalties applied upon meeting or falling short of performance standards (see Appendix A for a review of utility rate regulation in general and rate-of-return regulation and IR in particular).

2. The RPS statute of Hawaii was originally enacted in 2001 as Act 272, and modified in 2004 as Act 95. Under the RPS of Hawaii, "… "Renewable portfolio standard" means the percentage of electrical energy sales that is represented by renewable energy. [L 2001, c 272, §2; am L2004, c95, §4]"[3] The share of renewable energy[4] resources is required by law to increase from 8% in 2005 to 10% in 2010, 15% in 2015, and 20% in 2020.[5] An electric utility company and its affiliates may combine their

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[1] HRS § 269-95 (1) provides that the Commission shall "(1) 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, 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."

[2] HRS § 269-91 provides that "'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] *Ibid*.

[4] *Ibid*. "'Renewable energy' means 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. Where biofuels, hydrogen, or fuel cell fuels are produced by a combination of renewable and nonrenewable means, the proportion attributable to the renewable means shall be credited as renewable energy. Where fossil and renewable fuels are co-fired in the same generating unit, the unit shall be considered to produce renewable electricity in direct proportion to the percentage of the total heat value represented by the heat value of the renewable fuels. 'Renewable energy' also means electrical energy savings brought about by the use of solar and heat pump water heating, seawater air-conditioning district cooling systems, solar air-conditioning and ice storage, quantifiable energy conservation measures, use of rejected heat from co-generation and combined heat and power systems excluding fossil-fueled qualifying facilities that sell electricity to electric utility companies, and central station power projects."

[5] HRS § 269-92 provides that "Each electric utility company that sells electricity for consumption in the State shall establish a renewable portfolio standard of:
(1) Seven per cent of its net electricity sales by December 31, 2003;
(2) Eight per cent of its net electricity sales by December 31, 2005;
(3) Ten per cent of its net electricity sales by December 31, 2010;
(4) Fifteen per cent of its net electricity sales by December 31, 2015; and

renewable energy portfolios in order to meet the RPS.[6] The Commission may provide incentives for electric utility companies to exceed their RPS, to meet their RPS ahead of time, or both.[7]

3. Under the RPS of Hawaii, the Commission is to determine the impact of any proposed utility ratemaking structure on the profit margins of electric utility companies, and to ensure that such profit margins do not decrease as a result of implementing the proposed utility ratemaking structure.[8] Moreover, the Commission is to contract with the University of Hawaii in order to conduct independent studies on the capability of Hawaii's electric utility companies to achieve the RPS in a cost-effective manner, and on a variety of other factors potentially affecting RPS implementation, including those deemed appropriate by the Commission.[9] And the Commission is to report its findings on, and revisions to, the RPS to the legislature no later than 20 days before the convening of the regular session of 2009, and every five years thereafter. [L 2004, c95, pt of §2][10]

4. At the moment, all electric utilities in Hawaii appear to have satisfied the RPS of 7% of net electricity sales by December 31, 2003. The share of generation from non-fossil fuel energy and quantifiable energy conservation without solar water heating in total sales, for the year ended December 31, 2004, is 9% for the Hawaiian Electric Company, Inc. ("HECO"), 28% for the Hawaii Electric Light Company, Inc. ("HELCO"), and 12% for the Maui Electric Company, Limited ("MECO").[11] The share of net renewable generation and conserved energy in total sales, for the year ended December 31, 2004, is 13.2% for the Kauai Island Utility Cooperative ("KIUC").[12]

5. Economists Incorporated (http://www.ei.com), an economics consulting firm with offices in Washington D.C. and the San Francisco Bay Area, provides assistance to the Commission in developing a plan to formulate electric utility ratemaking structures as required by its legislative mandate. The conclusions emerging from this process are likely to form the basis of rules implementing a ratemaking structure

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(5) Twenty per cent of its net electricity sales by December 31, 2020.
The public utilities commission shall 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. If this determination is made, the electric utility company shall be relieved of responsibility for meeting the renewable portfolio standard for the period of time that it is unable to meet the standard. [L 2001, c 272, §3; am L 2004, c 95, §5]"

[6] *See* HRS § 269-93.

[7] *See* HRS § 269-94.

[8] *See* HRS § 269-95 (2).

[9] *See* HRS § 269-95 (3)(A).

[10] *See* HRS § 269-95 (4).

[11] *See* Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, *2004 Renewable Portfolio Standard Status Report For the Year Ended December 31, 2004*, June 27, 2005.

[12] *See* Kauai Island Utility Cooperative, *Renewable Portfolio Standards (RPS) Status Report Year Ending December 31, 2004*, March 18, 2005.

that could be adopted in a conventional rulemaking process. Such formally adopted rules to implement the RPS may be used by the Commission pursuant to its legislative requirements. The assistance provided to the Commission broadly has the following elements:

- Draw lessons from the components and IR mechanisms of other RPS programs;
- Identify inputs consisting of candidate RPS components and IR mechanisms for potential RPS implementation in Hawaii;
- Use the lessons drawn and inputs identified, among others, in computer simulations of electric power production in Hawaii to determine and evaluate candidate electric utility ratemaking structures;
- Evaluate the welfare implications and efficiency and equity effects of candidate electric utility ratemaking structures; and
- Formulate electric utility ratemaking structures from the best candidates.

B. Objectives and Scope of the Paper

6. The objectives of this paper are to survey and analyze the design and implementation of various RPS programs in the U.S., to examine potential alternative renewable energy resources in Hawaii, and to identify proposed or potential ratemaking structures and incentives consisting of candidate RPS components and IR mechanisms for implementing Hawaii's RPS.

7. Part II of this paper is an analysis, for each individual state, of the legislative design of RPS programs as embodied in statutes or legislation, and RPS implementation experience to date. Part III is a review of alternative renewable energy resources in Hawaii. Part IV is a description of candidate RPS components and IR mechanisms that may be used as inputs for implementing Hawaii's RPS.

C. Collaborative Workshops

8. The Commission is using a collaborative workshop approach to encourage public discussion of its work-in-progress, and is organizing three two-day workshops.[13] The first workshop was held on November 22 and 23, 2004. A second workshop is scheduled for October 2005.

9. This paper could serve as a starting point of discussions for the second workshop during which the following issues may be addressed: (a) certain RPS programs from other states for possible use in developing Hawaii's ratemaking structure that encourages the use of renewable energy; (b) potential renewable energy resources as candidate investment projects in Hawaii; and (c) how potential ratemaking structures and IR mechanisms can be used as components for ratemaking structures and incentives to implement the RPS program in Hawaii.

[13] *See* the Hawaii Public Utilities Commission, *Electric Utility Rate Design in Hawaii: An Initial Concept Paper*, November 1, 2004.

D. Highlights of First Workshop

10. More than 70 individuals representing industry, government, and public interest group stakeholders participated in the first workshop, and several of them provided written comments on the Initial Concept Paper (see Appendix B for a list of workshop participants and providers of written comments). Some of their main concerns expressed during the first workshop are summarized in the following paragraphs.

11. Stakeholders expressed a concern about the appropriate interpretation of Act 95. First, some assert that the Commission must make the RPS mandatory. And second, the RPS must be given enough time to produce any gains.

12. Stakeholders expressed a concern about the integration of the RPS with other proceedings pending at the Commission and current ratemaking issues. On-going proceedings, such as the Integrated Resource Planning ("IRP") dockets, competitive bidding dockets, rate cases, distributed generation dockets, and others, could be interrelated with the RPS, and may provide valuable information on candidate renewable energy projects that potentially can be installed in Hawaii. The planned Status Quo Simulation for analyzing the RPS may include assumptions on current ratemaking concerns, such as (a) the potential for cross subsidization between and among residential, commercial, and industrial customers, and (b) the absence of time-of-use and inverted block rates, which may be considered in other proceedings pending in the Commission.

13. Stakeholders expressed a concern about alternative regulatory regimes. First, various tools for IR, such as price caps and revenue caps, could have different effects on utility behavior, and some appear to be better suited to the achievement of RPS than others. Second, there may be a need to consider a system of tradable renewable energy generation credits. Third, PBR has not been used elsewhere as a tool to implement RPS, and therefore its efficacy is unlikely to be known completely. And fourth, alternative regulatory regimes must be given enough time to take effect.

14. Stakeholders expressed a concern about the modeling of renewable energy projects. First, there were questions on the eligibility of alternative renewable energy resources. There appears to be at least three types of renewable energy projects: a stand-alone central power station attached to a utility's system; a renewable energy project installed at customer premises; and an energy efficiency program implemented by the customer, the utility, or both. Second, some renewable energy projects may deserve a capacity credit in view of their expected contribution to system reliability. Third, there is a strong need to address the volatility of energy prices. Fourth, one proxy for environmental externalities is the price, expected to be around $10/ton to $40/ton, of carbon dioxide emission permits. Fifth, a reasonable time period for the planned production simulations, such as 20 years, is necessary to capture the effects of incentives. Sixth, it is important to reflect the constraints related to site permitting and land use policies, including transmission constraints. And seventh, there may be a need to determine the minimum efficient scale of renewable projects, especially in the context of technological change.

15. Stakeholders expressed a concern about the modeling of the financial operations of utilities. First, the financial viability of utilities is key to their ability to attract financing from capital markets. Regulation intimately affects utility behavior and the incentives for investment. Second, the differences between a

utility, such as HECO, and a cooperative, such as KIUC, in terms of their financial and economic features may be material to the planned production simulations and therefore seems worthy of further analysis. And third, it is crucial to find a proper base year reflecting different rate case years and "normal" business conditions.

16. Stakeholders expressed a concern about utility ratemaking structures. First, there seems to be a consensus that higher usage should have a higher price. Second, the design of ratemaking structures may require the assessment of several trade-offs. And third, the design of ratemaking structures may have to be coordinated with rate cases.

17. Finally, stakeholders expressed a concern about the transparency of the planned simulations of electric power production. First, it is important to have a transparent process in the analysis and modeling of the Commission's legislative mandate. And second, the production simulations are expected not only to address the issues pertaining to Act 95 but also to increase the understanding of how the Hawaii power sector works.

E. Status of Planned Simulations of Electric Power Production

18. Planned simulations of electric power production in Hawaii are proceeding in earnest. Data have been received from Hawaiian Electric Industries ("HEI") for HECO, HELCO, and MECO, and from KIUC. Assurances have been made that, if applicable, the proprietary format in which their data are submitted will be protected. Data integrity is being assessed, and preliminary Baseline and Status Quo Simulations for KIUC and HEI power systems are being performed.

19. The release of a companion technical paper describing the approach to the planned computer simulations of electric power production in Hawaii is expected in August 2005. The technical paper aims to describe, among others, the software tools, scenarios, geographic scope, base year, study period, special modeling routines, and the modeling of candidate renewable energy resources in Hawaii.

20. A one-day technical workshop is also scheduled for October 2005 for interested stakeholders providing inputs on the planned simulations. The technical paper could serve as a starting point of discussions for the technical workshop.

F. Comments

21. Comments are welcome and may focus on issues in the following paragraphs:

- Paragraph 106;
- Paragraph 121; and
- Paragraph 172.

II. Design and Implementation of RPS Programs

A. Overview[14]

22. The U.S. Department of Energy ("DOE") has prepared forecasts of renewable energy generation in the U.S. Electricity generated from renewable resources in the U.S. is likely to rise from 304 billion kWh in 2002 to 460 billion kWh in 2025. The share of renewable resources in total power generation in the U.S. is expected to remain at 9% in both 2002 and 2025.[15] The capacity for generating renewable energy in the U.S. is likely to increase from about 91 GW in 2002 to approximately 110 GW in 2025. The share of renewable resources in total power generation capacity in the U.S. is expected to remain steady between 2002, at about 11%, and 2025, at about 10%.[16] Wind generation capacity is likely to increase from about 5 GW in 2002 to 16 GW in 2025, or about half the increase in renewable energy capacity. The medium-term prospects of wind generation seem uncertain and probably depend on future cost and performance, transmission availability, the extension of the Federal production tax credit, other incentives, energy security, public interest, and environmental preferences.[17] Among alternative renewable energy resources, the most significant capacity additions are likely to come from biomass, wind, and geothermal rather than from solar.[18]

23. There is currently no Federal renewable energy mandate.[19] Several Federal and state instruments, such as financial incentives, rules, regulations, and policies, are in place to encourage renewable energy.

- Financial incentives include corporate tax incentives, direct equipment sales, grant programs, industrial recruitment incentives, leasing or lease purchase programs, loan programs, personal income tax incentives, production incentives based on energy output, property tax incentives, rebate programs, and sales tax incentives, among others.

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[14] The following discussion of state RPS policies and laws is not comprehensive and intends to provide a comparative overview. *See* original legal sources for a complete description of the various states' laws.

[15] *See* Energy Information Administration, *Annual Energy Outlook 2004*, January 2004, at 145 and 241. Renewables include conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power. In 2002 dollars, the reference case for world oil prices in 2025 is assumed to be $27/barrel. In nominal dollars, the reference case for world oil prices in 2025 is assumed to be $51/barrel. See Energy Information Administration, *Annual Energy Outlook 2005*, January 2005, at 3, for an assumption that, in 2003 dollars, the reference case for world oil prices in 2025 is $30/barrel, and that, in nominal dollars, the reference case for world oil prices in 2025 is $52/barrel. For an assessment that, "taking a 100 year view…the age of cheap oil is over," see Kyle Datta, *Testimony of the Rocky Mountain Institute on the Electric Utility Rate Design in Hawaii: An Initial Concept Paper*, November 15, 2004, at 11.

[16] *See* Energy Information Administration (2004), *Ibid* at 147.

[17] *Ibid* at 85.

[18] *Ibid.*

[19] *See* Thomas Petersik, *State Renewable Energy Requirements and Goals: Status Through 2003*, Energy Information Administration, at 1, available at http://www.eia.doe.gov/ last visited on December 6, 2004.

- Rules, regulations, and policies include construction and design policies (*e.g*. architectural guidelines), contractor licensing, equipment certification, generation disclosure rules, green power purchasing or aggregation policies, line extension analysis (*e.g*. information on on-site renewable energy substituting for extending a transmission line to a customer), net metering rules, public benefit funds, RPS/set asides ("RPS/SA"), required utility green power option, and solar and wind access laws, among others.[20] At the state level, RPS or RPS/SA policies are not the only means for promoting renewable energy resources.

24. The 22 states that have statewide renewable resource initiatives in the form of either RPS, RPS-style policies, or RPS/SA policies are Arizona, California, Colorado, Connecticut, Hawaii, Illinois, Iowa, Maine, Maryland, Massachusetts, Minnesota, Montana, Nevada, New Jersey, New Mexico, New York, Pennsylvania, Rhode Island, Texas, Washington D.C., and Wisconsin.[21] Under an RPS program or RPS-style policy, a certain percentage of current or new generation capacity (in MW), energy sales (in MWh), or energy growth has to be obtained from renewable energy sources. Under an RPS/SA policy, a certain level of renewable resources capacity is required among new generation capacity. Most of the 22 states have a RPS, RPS-style policy, or RPS/SA policy, but Minnesota has both RPS-style and RPS/SA policies, and Wisconsin has a RPS and a RPS/SA policy (see Table C1 in Appendix C).

25. Most RPS programs have been adopted over the last five to seven years and continue to be implemented. A few are expected to take effect over the next two years. The range of RPS percentages is wide (see Figure C1 in Appendix C). The percentage under the Arizona RPS, 1.1%, is the lowest, and that under the Maine RPS, 30%, is the highest. The two next highest RPS percentages are 25% for New York and 20% each for Hawaii and California. RPS-style policies are often in the nature of a goal, as in Illinois and Vermont, or a "good faith effort," as in Minnesota. States with RPS/SA policies have a wide range of renewable energy capacity requirements: 105 MW annually in Iowa, 1,125 MW of wind by 2010 and 125 MW of biomass by 2002 in Minnesota, 2,880 MW by 2009 in Texas, and 50 MW by 2000 in eastern Wisconsin (see Figure C2 in Appendix C).

26. The next five sections provide summaries of the legal foundation and implementation experience in individual states, excluding Hawaii. Each summary covers the RPS statutes or legislation and the RPS implementation experience to date. It includes data from the EIA, which has the following data definitions: pumped storage hydro is excluded from renewable energy resources, and non-hydro renewables exclude all hydro resources. Summaries are grouped according to three IR mechanisms, renewable energy credit ("REC") trading, alternative compliance fees, or penalties, typically found in RPS statutes (see Table C2 in Appendix C). Under a REC trading system, a utility may purchase RECs in order to meet some or all of its RPS requirements. Under a system of alternative compliance

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[20] *See* Datta, *Supra* Note 15 at 20, for an analysis of different types of funds, such as grants, reserves, or investments, that support project costs, subsidize debt service, provide equity at low rates of return, or guarantee low interest loans. For a view that substantial subsidies, more than rate design, are key to the promotion of renewable energy resources, see Lani D. H. Nakazawa, *Act 95 Workshops*, November 10, 2004, at 2.

[21] Jacksonville Electric Authority, a utility serving customers in Jacksonville and parts of three adjacent counties in Florida, has a commitment to allocate 4% of its generation capacity in 2007 and 7.5% in 2015 to renewable energy resources. Available at http://www.jea.com last visited on March 10, 2005. However, Florida is excluded from the list of 22 states because it does not have a statewide renewable energy policy.

fees, a utility can meet the RPS through the payment of fees to a renewable energy development fund. Under a system of penalties, a utility is charged a fine for energy generation that falls short of the RPS.

- Massachusetts and Rhode Island have REC trading, compliance fees, and penalties (see Section B).
- Connecticut, Maryland, Pennsylvania, Vermont, and Washington D.C. have only REC trading and compliance fees (see Section C).
- Maine, Montana, Nevada, New Jersey, New Mexico, Texas, and Wisconsin have only REC trading and penalties (see Section D).
- Arizona, Colorado, and Minnesota have only REC trading, and California has only penalties (see Section E).
- Illinois, Iowa, and New York do not have REC trading, compliance fees, or penalties (see Section F).

B. States With REC Trading, Compliance Fees, and Penalties

<u>Massachusetts</u>

Legal Foundation

27. In Massachusetts, the RPS, created through legislation on power sector restructuring, is specified to reach 4% by 2009 and to grow by one percentage point per year thereafter until suspended by the Division of Energy Resources ("DOER").[22] Electricity suppliers can meet the RPS in several ways. Renewable energy certificates traded through a market-priced bid-based power exchange system may be purchased. The RPS can be met through banked compliance. Excess compliance in one year can be used to satisfy compliance in another year. And the RPS can also be met through Alternative Compliance Payments ("ACP"). The ACP rises with inflation and can be used to advance renewable energy development in the state.[23] The adjusted rate for the ACP for 2005 has been determined to be $0.05319/kWh.[24]

    - A system benefit charge, included in the rate base, is expected to generate $20 million in annual revenue for the state's Renewable Energy Trust Fund that may be used to reach a goal of green generation of between 750 and 1,000 MW by 2009.[25] The Fund is to support initiatives generating the maximum economic and environmental benefits to ratepayers.[26]

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[22] *See* Massachusetts Division of Energy Resources, *Renewable Energy Portfolio Standard*, 225 CMR § 14.07, April 26, 2002 available at http://www.mass.gov/ last visited on January 31, 2005.

[23] *Ibid* at § 14.08.

[24] *See* http://www.mass.gov/doer/rps/index.htm last visited on June 14, 2005.

[25] *Supra* Note 22.

- An electricity supplier that fails to comply during a compliance year is to submit a plan to the DOER for achieving compliance for the subsequent three years. The DOER may refer its findings of non-compliance to the Department of Telecommunications and Energy, and an electricity supplier that fails to comply may be subject to licensure actions.[27]

Implementation

28. On November 25, 1997, the Governor approved the Electric Utility Restructuring Act, which requires the DOER to establish a RPS for all retail electricity suppliers and to create the Renewable Energy Trust for developing renewable energy.[28] The DOER began implementing the RPS on April 26, 2002.[29] Each year, the DOER determines an ACP that retail electricity suppliers can pay in lieu of meeting the RPS. Since the adoption of the RPS, the DOER has issued several advisory rulings approving the eligibility of different renewable energy plants.[30] The rulings have included proposals for creating new plants and modifying existing facilities.

29. In January 2005, the Renewable Energy Trust offered $25 million to support projects that could generate from 25 MW to 50 megawatts of renewable energy.[31] The Renewable Energy Trust obtains part of its funding from the sale of renewable energy certificates. The first round of funding in 2004 awarded $32 million to six projects that may generate nearly 100 megawatts of renewable energy. Recent auctions of certificates have produced an average price of $0.05132/kWh.[32] In 2002, renewable resources accounted for 6.9%, and non-hydro renewables, 4.9%, of total generation in Massachusetts.[33]

<u>Rhode Island</u>

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[26] *See* Massachusetts Electricity Restructuring Act, *Chapter 164 of the Acts of 1997* at § 68 available at http://www.mass.gov/ last visited on January 31, 2005.

[27] *Supra* Note 22 at § 14.12.

[28] *Ibid at* § 14.07.

[29] *Ibid* at § 14.00.

[30] *See* Massachusetts Division of Energy Resources, *Advisory Rulings on the Likely RPS-Eligibility of Generation Units*, 2003 to 2005 available at http://www.mass.gov/ last visited on January 31, 2005.

[31] *See* Massachusetts Technology Collaborative Press Release, "Renewable energy trust launches $25 million request for proposals," January 27, 2005 available at http://www.mtpc.org/ last visited on January 31, 2005.

[32] *See* Evolution Markets LLC, Evolution Markets Completes Auction of Massachusetts Renewable Certificates for Massachusetts Technology Collaborative, April 20, 2005 available at http://www.evomarkets.com last visited on June 14, 2005.

[33] *See* Energy Information Administration, *Renewable Energy Trends 2003*, July 2004, available at http://www.eia.doe.gov/ last visited on February 2, 2005.

Legal Foundation

30. In Rhode Island, the RPS, known as the Renewable Energy Standard, is scheduled to reach 16% by 2019. In 2020 and every year thereafter, the Rhode Island Public Utilities Commission is to determine if the RPS is no longer necessary. Compliance with the RPS may be achieved through the purchase of certificates or the provision of ACPs to a renewable energy development fund. The certificate is established under a Generation Information System operated by the New England Power Pool ("NE-GIS"). The ACP, adjusted annually for inflation, is $50/MWh of renewable energy obligation in 2003 dollars.[34]

- Through rates, electric utility distribution companies may recover all prudent incremental costs arising from the implementation of the RPS, such as NE-GIS certificates, ACPs, required payments to support the NE-GIS, and other assessments and costs. Companies failing to comply reasonably with the RPS may be subject to sanctions. No sanction or penalty may relieve an entity from liability for fulfilling any shortfall in compliance. Financial penalties resulting from sanctions due to non-compliance may not be recovered from rates.[35] There is already a system benefits charge supporting renewable energy. There are efforts to maximize the efficiencies associated with the combined effects of the system benefits charge and the RPS.[36]

- A renewable energy development fund was created to increase the supply of NE-GIS certificates available for RPS compliance in future years, and may be used for stimulating investments in renewable energy, issuing assurances and/or guarantees supporting the acquisition of renewable energy certificates, establishing escrows and reserves and/or acquiring insurance for the fund's obligations, and paying the fund's administrative costs.[37]

Implementation

31. The RPS begins in 2007 and the Rhode Island Commission has to develop and adopt regulations before December 31, 2005 to define the mechanisms of reporting and verification, standards for contracts for renewable resources, the details of the banked compliance mechanism, and sanctions for failure to comply with regulations.[38] In 2002, renewable resources accounted for 1.4%, and non-hydro renewables, 1.4%, of total generation in Rhode Island.[39]

C. States With REC Trading and Compliance Fees Only

[34] *See* State of Rhode Island General Assembly, *An Act Relating to Public Utilities and Carriers – Renewable Energy Standards*, 2004 – H7375, at § 39-26-2 and § 39-26-4.

[35] *Ibid* at § 39-26-6.

[36] *Ibid* at § 39-26-8.

[37] *Ibid* at § 39-26-7.

[38] *Ibid* at § 39-26-2 and § 39-26-4

[39] *Supra* Note 33.

Connecticut

Legal Foundation

32. In Connecticut, the RPS is scheduled to increase from 4% in 2004 to 10% in 2010 and beyond. The RPS provides for two classes of renewable technologies. Class I technologies are solar, wind, new sustainable biomass, landfill gas, fuel cells, ocean thermal power, wave or tidal power, low emission advanced renewable energy conversion technologies, and run-of-river hydro of at most 5 MW. Class II technologies are trash-to-energy facilities, non-Class I biomass facilities, and certain approved hydro facilities. The RPS is satisfied as combinations of Classes I and II: in 2004, 1% of Class I and 3% of Class I or II; and in 2010, 7% of Class I and 3% of Class I or II.[40]

- For the purpose of satisfying the RPS, Class I or Class II renewable resources may be purchased within the New England Power Pool ("NEPOOL"), the regional independent system operator of which Connecticut is part. They may also be purchased within the jurisdictions of New York, Pennsylvania, New Jersey, Maryland, and Delaware, as long as the Department of Public Utility Control ("DPUC") of Connecticut determines that those states have comparable RPS programs.[41]

- The cost of the RPS is covered through the rate base that includes a renewable energy investment charge and a system benefits charge. Electricity distribution companies failing to comply with the RPS within an annual period are required to pay $0.055/kWh of RPS shortage to the DPUC. Such payments are to be allocated to a Renewable Energy Investment Fund ("REIF") for the development of Class I renewable energy resources. The utility has to file with the DPUC long-term contracts for Class I renewable resource projects supported by the REIF at a price equal to the sum of the comparable wholesale market price for generation and $0.055/kWh.[42]

Implementation

33. The RPS of Connecticut nominally started in 2001. Under a two-tier RPS, the mandate did not apply to standard offer and default service, and as a result, the vast majority of load, over 99%, was exempt.[43] Moreover, due to weak enforcement, the RPS did not have much impact on the state's renewable energy supply. Thus, from 2003 to 2004, revisions were made by the State legislature and the DPUC established a series of dockets to shape a new law and to make determinations affecting the viability

[40] *See* Substitute Senate Bill No. 733, An Act Concerning Revisions to the Electric Restructuring Legislation.

[41] *Ibid.*

[42] *Ibid.*

[43] *See* Bob Grace, Ryan Wiser, and Mark Bolinger, *Renewable Portfolio Standards: Background and Analysis for New York State*, May 2, 2002, at 3.

and credibility of the RPS program.[44] The process is currently ongoing. In 2002, renewable resources accounted for 6.3%, and non-hydro renewables, 5.2%, of total generation in Connecticut.[45]

<u>Maryland</u>

Legal Foundation

34. In Maryland, the RPS is satisfied using two types of renewable resources: Tier 1, such as solar, wind, and biomass, among others; and Tier 2, such as hydro, waste-to-energy facilities, and poultry litter incineration, among others. The RPS is set by 2019 to reach 7.5% for Tier 1 and 0% for Tier 2 (although the share of Tier 2 is 2.5% from 2006 to 2018). An electricity supplier can meet the RPS by accumulating the equivalent amount of RECs, including those from customers installing renewable on-site generators.[46] Between January 1, 2004 and December 31, 2008, an electricity supplier may receive different levels of credit towards the RPS for energy derived from various renewable resources, such as solar, wind, methane, and the biomass fraction of biomass co-fired with other fuels.[47] The Maryland Commission is to establish a REC trading system.[48]

- A supplier failing to meet the RPS has to pay the Maryland Renewable Energy Fund a compliance fee of $0.02/kWh for Tier 1 shortfalls and $0.015/kWh for Tier 2 shortfalls. For industrial process load, compliance fees are to be assessed at rates between $0.008/kWh and $0.002/kWh for Tier 1 shortfalls but are not assessed at all for Tier 2 shortfalls.[49] The Maryland Energy Administration is to administer a Renewable Energy Fund that is to be used to make loans and grants supporting the creation of Tier 1 renewable resources in the state. The Fund consists of compliance fees, loan re-payments, investment earnings, and other sources.[50]

- The Maryland Commission may allow an electricity supplier to recover actual dollar-for-dollar costs incurred, including compliance fees, in complying with the RPS. Electricity suppliers can recover compliance fees from ratepayers for three reasons. First, if the cost of paying the compliance fee is less than that of purchasing the required Tier 1 renewable energy resources. Second, if Tier 1 resources are insufficient. Or third, if a wholesale electricity supplier defaults or fails to deliver RECs under a supply contract approved by the Public Service Commission.[51]

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[44] *See* State of Connecticut, Substitute Senate Bill No. 733, Public Act No. 03-135 "Revisions to the Electric Restructuring Legislation," June 6, 2003 available at http://www.cga.ct.gov/ last visited January 27, 2005.

[45] *Supra* Note 33*.*

[46] *See* Maryland Senate Bill 869, § 7-701 and § 7-703.

[47] *Ibid* at § 7-704.

[48] *Ibid* at § 7-708.

[49] *Ibid* at § 7-705.

[50] *Ibid* at § 7-707.

[51] *Ibid* at § 7-706.

Implementation

35. RPS legislation was passed in May 2004 and utilities have to begin complying in 2006.[52] The Public Service Commission is required to adopt regulations for the program by July 1, 2005. In 2002, renewable resources accounted for 5.0%, and non-hydro renewables, 1.6%, of total generation in Maryland.[53]

<u>Pennsylvania</u>

Legal Foundation

36. In Pennsylvania, the RPS is scheduled by 2020 to reach 18% consisting of 8% from Tier I sources and 10% from Tier II sources. Tier I sources are from new and existing solar, wind, low-impact hydro, geothermal, biomass, biologically derived methane, coal mine methane, and fuel cells. Tier II sources are from new and existing waste coal, distributed generation, demand-side management, large-scale hydro, municipal solid waste, pulping process and wood manufacturing byproducts, and integrated combined coal gasification. Through a *force majeure* clause, the Pennsylvania Public Utilities Commission may reduce the RPS obligation or recommend its elimination, depending on the availability of renewable energy resources.[54]

- The Pennsylvania Commission is to establish an "alternative" energy credit or REC program as needed to implement the RPS. One REC represents one MWh of qualified alternative electric generation. An electric distribution company or supplier may bank or place in reserve alternative energy credits for up to two years. The Pennsylvania Commission may impose administrative fees on alternative energy credit transactions. The level of the fee may not exceed the actual direct cost of processing the transaction.[55]

- If a distribution company or supplier fails to comply with the RPS, the Pennsylvania Commission may impose an ACP. The Pennsylvania Commission is to review the alternative energy market in order to determine any adjustments to the level of the ACP. ACPs are to be paid into a special fund, to be used solely for projects that increase electricity generation from renewable resources,[56] and are $45 per alternative energy credit.[57]

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[52] Maryland Public Services Commission, In the Matter of the Commission's Inquiry Into the Implementation of the Renewable Energy Portfolio Standard, Case No. 9019, August 27, 2004 available at http://webapp.psc.state.md.us/ last visited January 30, 2005.

[53] *Supra* Note 33.

[54] *See* Senate Bill 1030, the General Assembly of Pennsylvania, Session of 2004, at § 2 and § 3.

[55] *Ibid* at § 3.

[56] *Ibid* at § 3.

[57] *Ibid* at § 3, Subsection f-3.

Implementation

37. The Governor signed the RPS bill into law on December 7, 2004. The Act is to become effective 90 days after signing.[58] In 2002, renewable resources accounted for 2.4%, and non-hydro renewables, 1.3%, of total generation in Pennsylvania.[59]

<u>Vermont</u>

Legal Foundation

38. In June 2005, Vermont enacted a renewable energy goal specifying that each retail electricity provider in Vermont shall supply an amount of new renewable energy that is equal to its incremental energy growth between January 1, 2005 and January 1, 2012.[60] The retail electricity provider may meet this requirement through eligible new RECs, new renewable energy resources with RECs still attached, or a combination of RECs and renewable resources. No retail electricity provider shall be required to provide more than 10% of its calendar year 2005 retail electric sales with electricity generated by new renewable resources. This requirement shall apply to all retail electricity providers in Vermont, unless the retail electricity provider demonstrates and the Vermont Public Service Board ("VPSB") determines that compliance with the standard would impair the provider's ability to meet the public's need for energy services after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs. Eligible renewable energy is defined as "…energy produced using a technology that relies on a resource that is being consumed at a harvest rate at or below its natural regeneration rate." Eligible facilities are those created in 2005, or pre-2005 facilities that have been expanded to increase electrical output.

39. The VPSB shall meet on or before January 1, 2012 and determine the amount of qualifying renewable resources that have come into service or are projected to come into service between January 1, 2005 and January 1, 2013. If the VPSB finds that the amount of qualifying renewable resources coming into service during that time exceeds total statewide growth in demand between January 1, 2005 and January 1, 2012, or if it finds that the amount of qualifying renewable resources exceeds 10% of total statewide load for calendar year 2005, the portfolio standards shall not be in force. The VPSB shall make its determination by July 1, 2012. If the VPSB finds that the goal established has not been met, one year after the VPSB's determination the portfolio standards established shall take effect.[61]

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[58] *Ibid* at Section 9.

[59] *Supra* Note 33.

[60] *See* An Act Relating To Renewable Energy, Efficiency, Transmission, And Vermont's Energy Future at Sec. 3. 30 V.S.A. § 8004 (b).

[61] *Ibid* at Sec. 4. 30 V.S.A. § 8005 (d)(1).

- In lieu of, or in addition to purchasing tradeable RECs to satisfy the portfolio requirements, a retail electricity provider in Vermont may pay to a renewable energy fund established by the VPSB an amount per kWh as established by the VPSB.[62]

- A charge established by the VPSB shall be in an amount determined by the VPSB by rule or order that is consistent with the principles of least cost integrated planning. As circumstances and programs evolve, the amount of the charge shall be reviewed for unrealized energy efficiency potential and shall be adjusted as necessary in order to realize all reasonably available, cost-effective energy efficiency savings.[63]

- The VPSB may approve alternative forms of regulation for an electric company. It may offer incentives for innovations and improved performance that advance state energy policy, such as increasing the reliance on Vermont-based renewable energy.[64]

<u>Washington D.C.</u>

Legal Foundation

40. The Council of the District of Columbia adopted the Renewable Energy Portfolio Standard Act of 2004 in January 2005, and the D.C. Public Service Commission is required to implement it.[65] The RPS has two tiers of renewable resources. Tier one consists of biomass, geothermal, landfill gas, ocean (*i.e*. mechanical and thermal), solar, wastewater-treatment gas, wind, and fuel cells using tier one resources. Tier two consists of hydropower (*i.e.* non-pumped storage generation) and waste-to-energy. The RPS increases from 1.5% from tier one, 2.5% from tier two, and 0.005% from solar energy in 2007 to11% from tier one, none from tier two, and 0.386% from solar energy in 2022.

    - Energy from existing renewable generating systems and facilities are eligible to satisfy the RPS, and energy from tier one can be used to satisfy the requirements of tier two. Compliance is achieved through the acquisition of RECs, and the D.C. Commission is to create a market-based REC trading system. In the event of non-compliance, a utility pays compliance fees of $0.025/kWh for shortfalls in tier one resources, $0.01/kWh for tier two shortfalls, and $0.30/kWh for solar shortfalls. The D.C. Commission is to create a Renewable Energy Development Fund to administer the levied funds that can be used to finance renewable projects.[66]

    - The D.C. Commission shall allow the local distribution company to recover actual dollar-for-dollar prudently costs incurred in complying with the RPS. The electricity distribution company may also

[62] *Ibid* at Sec. 3. 30 V.S.A. § 8004 (e).

[63] *Ibid* at Sec. 6. 30 V.S.A. § 209 (d)(4).

[64] *Ibid* at Sec. 11. 30 V.S.A. § 218 (d)(a)(4).

[65] *See* Renewable Energy Portfolio Standard Act of 2004.

[66] *Ibid* at Sec. 8.

pass through its prudently incurred additional costs, if any, associated with complying with the RPS. An electricity supplier may recover a compliance fee if (a) the payment of a compliance fee is the least-cost measure to ratepayers as compared to the purchase of tier one renewable sources, tier two renewable sources, or solar energy to comply with the RPS; or (b) there are insufficient tier one renewable sources, tier two renewable sources, or solar energy available for the electricity supplier to comply with the RPS.[67]

D. States With REC Trading and Penalties Only

<u>Maine</u>

Legal Foundation

41. In Maine, the RPS, enacted as part of Maine's efforts on power sector restructuring, requires competitive electricity providers to supply at least 30% of their total retail sales in Maine from renewable resources. A renewable resource is defined as a "small power production facility" using biomass or waste and having a capacity of at most 80 MW including other facilities on-site. It may also be a generation facility that has at most 100 MW of capacity and uses fuel cells, tidal power, solar arrays and installations, wind, geothermal, hydro, biomass, or municipal solid waste. The RPS can also be satisfied with "efficient resources," such as qualified cogeneration facilities. The Maine Commission is to review the 30% RPS and recommend any changes at most five years after the beginning of retail competition,[68] which began in March 2000.[69]

- Electricity providers failing to comply with the 30% RPS are subject to penalties, such as license revocation, an optional payment into a renewable resource research and development fund, or other monetary penalties determined by the Maine Commission.[70]

- The Maine Commission plans to establish a program allowing retail consumers to make voluntary contributions to fund renewable resource research and development. The fund is non-lapsing and administered by the State Planning Office.[71]

Implementation

42. In 2002, renewable and energy efficiency resources supplied approximately 38% of Maine's load,[72] and hydroelectric, biomass, municipal solid waste, wind, and solar, which were all designated as renewable

[67] *Ibid* at Sec. 7.

[68] *See* Maine Statutes, Title 35-A, § 3210, Renewable Resources.

[69] *See* Maine Statutes, Title 35-A, § 3202, Retail Access; Deregulation.

[70] *See* Maine Public Utilities Commission 65.404, Ch. 311 (Docket No. 98-619; 2002-494), at 9.

[71] *Supra* Note 68.

[72] *See* State of Maine Public Utilities Commission, *2003 Annual Report*, February 1, 2003, at 25.

under the Restructuring Act, supplied 31.9%.[73] In 2002, NEPOOL created a "tradable attribute" certificate system, the Generation Information System, which allows the trade of electricity attributes, such as fuel and emissions levels, separately from the energy commodity. In 2003, the Maine Commission required suppliers to demonstrate compliance with Maine's 30% RPS through NE-GIS certificates. The requirement is expected to reduce supplier compliance costs and simplify verification.[74] In 2002, hydro and renewable energy accounted for 32% of total generation in Maine.[75]

Montana

Legal Foundation

43. The Montana RPS, enacted in April 2005, requires utilities to increase the share of eligible renewable sources in all retail electricity sales from 5% of in 2008 to 15% in 2015.[76] To be eligible, facilities must be within Montana or must be a new facility, established after January 1, 2005, that serves Montana. The penalty for non-compliance, $10/MWh of the shortfall in RECs, cannot be passed along to consumers. Proceeds from penalties are directed to a universal low-income energy assistance fund. Excess compliance can be carried forward for at most two-years.

- In meeting the RPS, a public utility has to purchase both electricity and RECs from community renewable energy projects, which are eligible renewable resources (a) that are interconnected on the utility side of the meter, (b) in which local owners have a controlling interest, and (c) that are less than or equal to 5 MW in total calculated nameplate capacity. The sum of the nameplate capacities of community renewable energy projects from which a public utility has purchased is required to be 50 MW for the 10% milestone and 75 MW for the 15% milestone. The utility may recover from ratepayers the cost of renewable energy contracts that have been approved by the Montana Commission.[77]

- A public utility may petition the commission for a short-term waiver from full compliance with the RPS and the penalties levied. The petition must demonstrate that (a) the public utility has undertaken all reasonable steps to procure RECs under long-term contract, but full compliance cannot be achieved either because RECs cannot be procured or for other legitimate reasons that are outside the control of the public utility; or (b) integration of additional eligible renewable resources into the electrical grid will clearly and demonstrably jeopardize the reliability of the electrical system, and the public utility has undertaken all reasonable steps to mitigate the reliability concerns.[78]

[73] *Supra* Note 33.

[74] *Supra* Note 72.

[75] *See* http://www.eia.doe.gov/ last visited on January 11, 2005.

[76] *See* Renewable Power Production and Rural Development Act, Senate Bill No 415, Sec. (4)(2) and (4)(4)(a).

[77] *Ibid* at Sec. (5)(4).

[78] *Ibid* at Sec. (4)(11)(b).

Nevada

Legal Foundation

44. In Nevada, the RPS is scheduled to reach 15% by 2013. In each calendar year, a minimum of 5% of the renewable energy generation has to be obtained from solar. Retail energy providers planning to comply with the RPS may purchase RECs. The Nevada Public Utilities Commission determines whether or not the terms and conditions of a renewable energy contract are just and reasonable. The provider may recover all just and reasonable costs associated with an authorized renewable energy contract. If the Nevada Commission determines that, for a calendar year, there is insufficient supply of renewable energy resources under just and reasonable terms and conditions, then the provider is exempt for that year from the remaining requirements of its RPS or from any appropriate portion thereof.[79]

- Nevada provides an incentive to solar energy provided by retail customers. A provider is deemed to have generated or acquired 2.4 kWh from a renewable energy system for each 1 kWh of actual electricity generated or acquired from a solar system as long as two conditions are satisfied: (1) if the system is installed on the premises of a retail customer; and (2) on an annual basis at least 50% of the system's electricity generation is utilized by the retail customer on its premises.[80]

- The Nevada Commission was authorized to adopt enforcement mechanisms. Enforcement mechanisms may include, without limitation, the imposition of administrative fines. The fine may be based on each kWh of electricity that has not been generated or acquired from a renewable energy system. In the aggregate, the fines imposed on a provider for all violations of the RPS must not exceed the amount necessary and reasonable to ensure that the provider complies with its RPS. The fine is not a cost of service of the provider, the provider is to exclude any portion of the fine in any application for a rate adjustment or increase, and the provider is disallowed from recovering any portion of the fine from its retail customers.[81]

Implementation

45. The early performance of the Nevada RPS is generally disappointing.[82] Only a small quantity of electricity statewide has been generated by new renewable energy systems. The utilities and other stakeholders appear to agree that the utilities, which were unable to comply fully with the RPS in 2003,

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[79] *See* Portfolio Standard for Renewable Energy and Energy From a Qualified Energy Recovery Process, Nevada Revised Statutes, at NRS 704.7821.

[80] *Ibid* at NRS 704.7822.

[81] *Ibid* at NRS 704.7828.

[82] *See* Kevin Porter, Robert Grace, and Ryan Wiser, *Summary of Recommendations: Legislative and Regulatory Actions to Consider For Ensuring the Long-Term Effectiveness of the Nevada Renewable Portfolio Standard (Draft)*, December 3, 2004 available at http://energy.state.nv.us/ last visited on January 27, 2005.

are likely to have difficulty in complying with the RPS in 2004, 2005, and perhaps beyond. The RPS gives the Nevada Commission the authority to impose a penalty on a Nevada utility for failing to comply unless the utility successfully seeks an RPS waiver for that year. The Nevada Commission has granted all utility petitions for waivers, and has yet to impose penalties for RPS non-compliance.

46. Installing renewable projects has been difficult. For example, Nevada Power had signed a deal with the MNS Wind Company for a 260 MW wind farm in Shoshone Mountain on the Nevada Test Site. At the last minute, however, the Air Force halted the project, and said that the windmills could interfere with radar.[83] Two projects by Sierra Pacific, a wind farm in Ely and a solar plant near Boulder City, are currently delayed due to financing problems. Although Sierra Pacific's credit rating is reportedly a major barrier, financiers are believed to be concerned about the viability of what is viewed as a fledgling industry, although banks have funded large-scale fossil-fuel projects for utilities with less attractive credit than Sierra Pacific.[84]

47. There have been several efforts to improve compliance with the RPS. A workshop was held on November 4, 2004 in order to address additional measures that could strengthen the Nevada RPS, and to consider the implications for and potential interaction with RPS policies in nearby states. In 2002, renewable resources accounted for 10.6%, and non-hydro renewables, 3.5%, of total generation in Nevada.[85]

<u>New Jersey</u>

Legal Foundation

48. In New Jersey, the RPS is scheduled by 2012 to reach a total share of 6.5% consisting of 4% for Class I and 2.5% for Class II renewable resources. Class I renewable energy sources include wind, solar, fuel cells, geothermal, wave, methane, and other biomass cultivated and harvested in a sustainable manner. Class II renewable energy resources include hydro with at most 30 MW of capacity and resource recovery facilities.[86]

- Renewable resources that are eligible under the RPS are generation from small renewable resources with at most 100 kW of capacity, and any renewable energy from small on-site generation not scheduled through the Pennsylvania-New Jersey-Maryland ("PJM") Independent System Operator ("ISO") or the New York ISO ("NYISO").[87] The New Jersey Board of Public

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[83] *See* Brian Bahouth, "Moving Beyond Coal," Reno News and Review, July 8, 2004 available at http://www.newsreview.com/ last visited on January 27, 2005.

[84] *Ibid.*

[85] *Supra* Note 33.

[86] *See* Interim Renewable Energy Portfolio Standards, Subchapter 8, NJAC 12:4-8, at § 14:4-8.2, § 14:4-8.3, and § 14:4-8.4.

[87] *Ibid* at § 14:4-8.4.

Utilities, in consultation with the New Jersey Department of Environmental Protection, plans to develop a renewable energy trading program.[88]

- A supplier failing to meet its RPS is required to make up the kWh in arrears in subsequent years. A supplier unable to cover its current year's RPS requirement and any previous year's kWh arrears is in violation, and may be subject to the following penalties: suspension or revocation of license, financial penalties, disallowance of cost recovery in rates, and prohibition on accepting new customers.[89]

Implementation

49. In 2003, the number of solar systems more than doubled and nearly 100 new solar energy companies set up operations in New Jersey.[90] The initial success prompted the New Jersey Commission and state legislature to consider revising the RPS requirements. The Governor accepted recommendations from a Renewable Energy Task Force to increase the initial RPS targets specified by legislation. A report, issued in April 2003, recommends an increase in the 2008 target from 2% to 4%; an extension to 2020 with a 20% target; the establishment of two pro-renewable energy voluntary programs for utility customers; and the formulation of programs promoting solar energy.[91] In 2002, renewable resources accounted for 2.2%, and non-hydro renewables, 2.2%, of total generation in New Jersey.[92]

<u>New Mexico</u>

Legal Foundation

50. In New Mexico, the RPS is scheduled to increase from 5% in 2006 to 10% in 2011. Renewable energy certificates serve as documentation of transactions between public utilities and suppliers of renewable energy, and may be traded. Certificates have the following values: each kWh of solar counts as 3 kWh of RPS compliance, and each kWh of biomass, geothermal, landfill gas, or fuel cell count as 2 kWh of RPS compliance. Each public utility is asked to offer a voluntary renewable energy tariff, to be filed with the New Mexico Public Regulation Commission, for customers wanting an option to purchase additional renewable energy.[93] Rural electric cooperatives are exempt from the RPS, except for the requirement to offer a renewable energy tariff, if such renewable resources are available to them.[94]

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[88] *Ibid* at § 14:4-8.7.

[89] *Ibid* at § 14:4-8.8.

[90] *See* New Jersey Board of Public Utilities, Office of Clean Energy, *Clean Energy Program 2003 Annual Report*, available at http://state.nj.us last visited March 11, 2005.

[91] *See Renewable Energy Task Force Report Submitted to Governor James E. McGreevey*, April 24, 2003 available at http://www.state.nj.us/ last visited January 27, 2005.

[92] *Supra* Note 33.

[93] *See* Renewable Energy as a Source of Electricity, Title 17, Chapter 9, Part 573, § 17.9.573.10.

[94] *Ibid* at § 17.9.573.14.

- The RPS requires each public utility to file a renewable energy plan with the New Mexico Commission. The plan is to describe the different renewable energy technologies, the manner of generation or procurement, and how the RPS is satisfied. It also is to discuss other issues, such as transmission capacity, dispatch flexibility, and environmental benefits, among others. It also has to explain timing, contracting, incentives, and cost recovery mechanisms.[95] The New Mexico Commission plans to promulgate rules for administration and enforcement. The rules include provisions on the imposition of fines and mechanisms that are necessary and reasonable to ensure compliance.[96]

- Public utilities, in meeting the RPS, are able to recover through the ratemaking process their reasonable costs incurred in procuring or generating energy from renewable resources. They are not required to acquire renewable energy that could result in costs above a reasonable cost threshold determined by the New Mexico Commission. If a public utility can generate or procure renewable energy at or below the reasonable cost threshold, then it is required to add renewable resources as specified in the RPS.[97]

- The New Mexico Commission may modify the reasonable cost threshold as changing circumstances warrant, such as the commodity costs of renewable energy, transmission and interconnection costs, tax credit availability for renewable energy projects, impact of renewable energy on retail customer rates, and reliability, among others.[98]

Implementation

51. New Mexico's RPS does not begin until January 1, 2006. The Renewable Energy Act, passed on March 4, 2004, strengthens the RPS by establishing more palpable cost caps and thresholds, and by developing an out-of-state trading system.[99] The act establishes a reasonable cost threshold, whose level would be determined in future by the New Mexico Commission. The act also tasks the New Mexico Commission with the creation of a system of tradable renewable energy certificates. In 2002, renewable resources accounted for 0.9%, and non-hydro renewables, 0.1%, of total generation in New Mexico.[100]

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[95] *Ibid* at § 17.9.573.11.

[96] *Ibid* at § 17.9.573.15.

[97] *See* Senate Bill 43, 46th Legislature, State of New Mexico, Second Session, 2004, at § 2 and § 4.

[98] *Ibid* at § 4.

[99] *See* State of New Mexico, 46th Legislature, Second Session 2004, *Senate Bill 43* available at http://legis.state.nm.us/ last visited on January 28, 2005.

[100] *Supra* Note 33.

Texas

Legal Foundation

52. In Texas, the RPS[101] aims to ensure that the cumulative installed renewable energy capacity in Texas is at least 2,880 MW by 2009. The trading of RECs ensures that new renewable energy capacity is built most efficiently and economically. A REC represents one MWh of renewable energy metered and verified in Texas. RECs may be generated, transferred, or retired by market participants. A REC is awarded to the owner of a renewable energy resource when a MWh is metered at that renewable energy resource.[102]

- A competitive retailer is responsible for retiring sufficient RECs in order to be in compliance. If a competitive retailer has insufficient RECs to satisfy its obligations, it is subject to penalties assessed on the deficient RECs. The penalty is the lesser of $50/MWh or, upon the presentation of suitable evidence, 200% of the average market value of RECs for the compliance period. There is no penalty if the Texas Public Utilities Commission determines that events beyond the reasonable control of the retailer, such as weather-related damage, mechanical failure, lack of transmission capacity or availability, strikes, lockouts, and actions of government, have prevented it from being in compliance.[103]

- The above-market costs of a renewable energy facility must not be included in the rates of any utility, municipally-owned utility, or distribution cooperative through base rates, a power cost recovery factor, stranded cost recovery mechanism, or any other fixed or variable rate element charged to end users.[104]

Implementation

53. Texas is widely considered to have the most successful RPS in the nation. The RPS contains strong penalties for non-compliance and uses REC trading and flexibility mechanisms to reduce costs. The 1999 renewable energy mandate in Texas has resulted in more new renewable energy generating capacity than any other state-level requirement to date. A substantial amount of renewable capacity became available in 2001 because of the RPS. More than 1,100 MW of renewable energy have already been installed. The state is well ahead of its 2005 target of 850 MW.[105] The oversupply is

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[101] *See* City Council of Austin Resolution 030925-02, adopted September 25, 2003 available at http://www.austinenergy.com/ last visited on March 10, 2005 for a report that the City Council of Austin, Texas adopted a resolution indicating that, among others, the RPS for Austin Energy has a goal of reaching 20% by 2020.

[102] *See* Chapter 25, *Substantive Rules Applicable to Electric Service Providers*, Subchapter H, Electrical Planning, Division 1, Renewable Energy Resources and Use of Natural Gas, at § 25.173.

[103] *Ibid*.

[104] *Ibid.*

[105] *See* Union of Concerned Scientists, *Renewable Electricity Standards at Work in the States (Fact Sheet)*, January 2005 available at http://www.ucsusa.org/ last visited on January 27, 2005.

expected to keep compliance costs low. For example, there are wind contracts that apparently have been signed for less than $0.025/kWh.[106] In 2002, renewable resources accounted for 1,905 MW of net summer capacity in Texas.[107]

Wisconsin

Legal Foundation

54. Wisconsin has a RPS and a RPS/SA policy. Each is discussed below.

- Under the RPS, each electric provider by December 31, 2011 is to obtain 2.2% of its retail energy sales from renewable energy. An electric provider may comply with the RPS through the generation or purchase of electricity from renewable resources, or through the purchase of RECs from another electric provider that has excess RECs. The Wisconsin Public Service Commission allows utilities to recover the full cost of compliance through their rates, such as an equal allocation to all customers on a per kWh basis, alternative pricing structures, including premium payments for renewable energy, or any combination of these methods. Violation of the RPS or submission of false or misleading information on renewable energy sources is subject to a forfeiture of between $5,000 and $500,000.[108]

- Under the RPS/SA, each eastern Wisconsin utility was to construct or procure by December 31, 2000 an aggregate of 50 MW of renewable energy generation capacity. The Wisconsin Commission is to allow an eastern Wisconsin utility to recover from its retail electric rates any costs that are prudently incurred in complying with the RPS/SA.[109]

Implementation

55. Compliance with the RPS has apparently been achieved. Wisconsin utilities are in compliance through 2003, and have "banked" enough excess renewable kWh to achieve the 2011 target of 2.2%. Such early compliance has raised a few concerns, however. Several years of market stagnation may follow before additional renewable capacity is added.[110] Because REC banking is allowed, the current over-compliance may be banked and used in future compliance periods, and few incremental renewable energy investments may be needed for a number of years. And because less expensive renewable energy options are located out-of-state, Wisconsin may be exporting some of the benefits of its RPS.[111]

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[106] *Supra* Note 43 at 6.

[107] *Supra* Note 33.

[108] *See Information Memorandum 99-6 on Wisconsin Act 9 1999*, at 34-36. See also Regulation of Public Utilities, *Chapter 196*, § 196.378.

[109] *See 1997 Wisconsin Act 204*, § 27. See also Regulation of Public Utilities, *Chapter 196*, § 196.377.

[110] *Supra* Note 43 at 6.

[111] *Supra* Note 43 at 7.

In 2002, renewable resources accounted for 6.3%, and non-hydro renewables, 2.0%, of total generation in Wisconsin.[112]

E. States With REC Trading or Penalties Only

REC TRADING ONLY

Arizona

Legal Foundation

56. In Arizona, the RPS is scheduled to increase from 0.8% in 2004 to 1.1% in the period from 2007 to 2012. From 2004 to 2012, the share of solar electric in the renewable portfolio is expected to be 60%. Under the RPS, the Arizona Corporation Commission is expected to increase the RPS percentage annually only if the cost of renewable power drops to a pre-approved point. A load-serving entity ("LSE") can obtain credits on its RPS obligation from the installation and operation of new solar electric systems, the in-state installation of a power plant, the in-state manufacture and installation of related equipment, or distributed solar generation.[113]

- An LSE serving a customer with on-site photovoltaic ("PV") or solar thermal resources can count them toward its applicable RPS. An LSE producing or purchasing eligible kWh in excess of its RPS requirement can save or bank the excess kWh for use or sale in future. An LSE is entitled to meet up to 20% of the RPS requirement with solar water heating systems or solar air conditioning systems purchased by the LSE for its customers' use, or purchased by its customers and paid by the LSE through bill credits or other similar mechanisms.[114]

- The cost of the RPS is recovered through system benefits charges, an environmental portfolio surcharge on each customer's monthly bill, and a re-allocation of demand-side management ("DSM") funding.[115] It is also recovered from green power programs encouraging consumers voluntarily to pay a premium for environmentally friendly power.[116] The environmental portfolio surcharge, assessed monthly, is the smaller of $0.000875/kWh or $0.35/service for residential customers, $13/service for non-residential customers, and $39/service for non-residential customers whose metered demand is at least 3 MW for three consecutive months.[117]

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[112] *Supra* Note 33.

[113] *See* Arizona Corporation Commission, R14-2-1618, Environmental Portfolio Standard, available http://www.cc.state.az.us/ last visited on January 12, 2005.

[114] *Ibid*.

[115] *Ibid.*

[116] *Supra* Note 19 at 4.

[117] *Supra* Note 113.

Implementation

57. In 2003, at least one utility was expected to meet the so-called Environmental Portfolio Standard ("EPS"), or Arizona's RPS, of 1.1% by 2012 or earlier. Apart from this one exception, no utility has met the annual renewable energy targets on the existing timeline. Funds seem to have been insufficient. Another possible reason is that utility-specific factors pre-dating the EPS may affect the ability of utilities to meet the EPS, such as access to inexpensive generation from other renewable technologies, and whether or not the Arizona Commission authorized the use of System Benefit funds.[118]

58. Under the original 2001 plan, the EPS called for a review in 2004 to determine if the costs of meeting the RPS had fallen to an approved point and, therefore, if the RPS percentage should be frozen at 0.8% or allowed to increase as anticipated. On February 10, 2004, the Arizona Commission decided to approve increases in the EPS percentages to 1.0% in 2005, 1.05% in 2006, and 1.1% from 2007 to 2012. Moreover, the Arizona Commission's decision, which did not affect rates, called for workshops to study possible changes in the EPS, such as an increase in the total portfolio requirement; a change in funding levels and options from the current mix of special programs, rate structures, and the portfolio surcharge; an extension of the EPS beyond 2012; a return of DSM funds to its original purpose rather than the current policy of shifting them to renewable resources; and the appropriateness of the portfolio structure.[119] In or around October 29, 2004, the Arizona Commission approved a pilot program to allow the inclusion of solar heating, ventilation, and air conditioning ("HVAC") systems as qualifying technologies in its EPS.[120]

59. By 2003, the utilities have installed a diverse range of solar and non-solar projects. Renewable projects installed to meet the EPS at the end of 2002 include almost 6 MW of various PV installations, a 5 MW landfill project, and a large, solar hot water system displacing about 200 kW of peak electric demand. Some promising PV and solar thermal technologies have good potential for cost reduction, but may not be the least-cost option. It seems beneficial to allow utilities to support new products and technologies that they have selected in order to find further cost reductions. As a direct result of the EPS, utilities in Arizona have more installed capacity of large, utility-scale PV systems than other investor-owned electric utilities in the U.S.[121] In 2002, non-hydro renewable resources accounted for 0.2% of total generation in Arizona.[122]

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[118] *See* Cost Evaluation Working Group, *Costs, benefits, and impacts of the Arizona Environmental Portfolio Standard*, June 30, 2003 available at http://www.cc.state.az.us/ last visited on January 27, 2005, at 1 and 2.

[119] *See* Arizona Corporation Commission News Releases, "Commissioners boost renewable energy requirement," February 11, 2004 available at http://www.cc.state.az.us/ last visited on January 27, 2005.

[120] *See* Arizona Corporation Commission News Releases, "ACC approves solar HVAC pilot program," October 29, 2004 available at http://www.cc.state.az.us/news/pr10-29-04.htm last visited on January 27, 2005. Solar HVAC technology can save energy that a customer would otherwise need to draw from the grid. In Arizona, energy consumption rises dramatically in summer due to intense demand for air conditioning. In summer, a solar HVAC system could provide cooling, and in other seasons, energy captured through an HVAC system can be used for space or water heating.

[121] *Supra* Note 118 at 1 and 2.

[122] *Supra* Note 33.

Colorado

Legal Foundation

60. In Colorado, the RPS,[123] also known as a renewable energy requirement, is scheduled to increase from 3% in 2007 to 10% in 2015 and beyond. The RPS applies to utilities serving at least 40,000 customers. A qualifying utility has to obtain at least 4% of its renewable electricity generation each year from solar, and at least half of this 4% has to be from solar systems located on customer premises. A qualifying utility may count 1 kWh of in-state renewable generation as 1.25 kWh towards its RPS. It may also count both RECs purchased under a REC trading system, and any verified generation savings from energy efficiency and conservation programs, toward its RPS obligation.[124]

- A qualifying utility may offer a standard rebate of at least $2.00/watt for the installation of up to 100 kW of eligible solar generation on the customer's premises. A utility may hold an election among its customers voting for inclusion or exemption from the RPS.[125]

- The Public Utilities Commission of Colorado has to approve the terms and conditions of renewable energy contracts between a utility and another party. Such contracts, including those for acquiring RECs from facilities in customer premises, are required to have a minimum term of 20 years. The Colorado Commission of plans to approve retail rates sufficient to recover all just and reasonable costs associated with approved contracts.[126]

- If a qualifying utility's investments in renewable energy technologies provide net economic benefits to customers as determined by the Colorado Commission, then it is allowed to earn its most recent authorized rate of return plus a bonus limited to 50% of the net economic benefit. If its investments do not provide net economic benefits to customers, then it is allowed to earn its most recent authorized rate of return, but no bonus. The maximum retail rate impact on an average residential customer is limited to $0.50/month.[127]

Implementation

61. On November 2, 2004, Colorado voters approved an amendment to the Colorado Revised Statutes, a proposed RPS, which took effect on December 1, 2004.[128] The Colorado Commission is required to

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[123] *See* City of Fort Collins, Colorado, *Electric Energy Supply Policy*, March 25, 2003, at 4 for a report that the City Council of Fort Collins, Colorado approved a policy requiring that, among others, the RPS for the City is to reach 15% by 2017.

[124] *See* Colorado General Assembly, Amendment 37, Article 2, at 39-41.

[125] *Ibid* at 41 and 43-44.

[126] *Ibid* at 42.

[127] *Ibid* at 41-42.

[128] *See* Colorado Public Utilities Commission Acting Director, *Public Notice on Amendment 37 Workshops*, February 11, 2005 available at http://www.dora.state.co.us/ last visited on March 10, 2005.

adopt regulations enforcing the renewable statutes on or before April 1, 2005.[129] A rulemaking process, which has to be finished by March 31, 2006, was established to give utilities time to meet the requirements for 2007. The Colorado Commission also has to decide on how to penalize utilities that fail to meet the deadlines. In 2002, renewable resources accounted for 3.0%, and non-hydro renewables, 0.4%, of total generation in Colorado.[130]

<u>Minnesota</u>

Legal Foundation

62. Minnesota has both RPS/SA and RPS-style policies. Under the RPS/SA policy, utility Xcel Energy has been required to build or contract for 1,125 MW of wind generation capacity by 2010 and 125 MW of biomass by 2002.[131] Under the RPS-style policy, utilities other than Xcel Energy are required to make a good faith effort to generate or procure 10% of their retail energy sales from renewable resources by 2015. The Minnesota Public Utilities Commission, as needed, is to issue an order determining whether or not a utility is making the required good faith effort.[132] It may establish a program for tradable RECs. An electric utility may then purchase sufficient RECs in order to meet its objective.[133]

Implementation

63. Mandated wind capacity amounting to 476 MW is being acquired on schedule, but biomass acquisitions, 25 MW through December 31, 2003, have not been accomplished because of difficulties encountered with technology and financing.[134] Due to changes in the RPS in 2003, the Minnesota Commission is in the process of issuing notices and receiving comments on various issues. The 2003 amended legislation directed the Minnesota Commission to issue an order by June 1, 2004 on the development of criteria and standards by which it can measure an electric utility's good faith efforts to meet the renewable energy objective ("REO"); the inclusion of criteria and standards that protect against undesirable impacts on system reliability and ratepayers, and consider technical feasibility; and the development of a weighting scale for counting renewable energy generation towards a utility's objective, and a system for granting multiple credits for technologies and fuels whose development are determined to be in the public interest.

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[129] *See* Amendment 37, Article 2 of title 40, CO Revised Statutes.

[130] *Supra* Note 33.

[131] *See* Minnesota Statutes § 216B.2423.

[132] *See* Renewable Energy Objectives, Minnesota Statutes §216B.1691 at Subdivision 2.

[133] *Ibid* at Subdivision 4.

[134] *Supra* Note 19.

64. On June 1, 2004, the Minnesota Commission issued its Initial Order Detailing Criteria and Standards for Determining Compliance with Minn. Stat. §216B.1691.[135] In its Order, the Minnesota Commission delegated to the Executive Secretary the authority to issue notices, to develop questions, and to establish further procedures resolving the remaining issues in the docket. The issues include, but are not limited to, reporting requirements, developing a weighted scale, specific criteria and standards for Xcel, tracking systems, voluntary compliance and reporting by municipal utilities, and tradable RECs. On June 2, 2004, a Notice of Comment Periods and Further Procedures[136] asked parties to respond by July 1, 2004, with replies by July 20, to specific questions related to weighting and the use of tradable RECs prior to the establishment of a system by the Minnesota Commission.

65. On August 5, 2004, the Commission considered petitions for reconsideration of the June 1 Order.[137] The Commission's Order After Reconsideration was issued on August 13, 2004. The Commission modified its decision on the issue of whether energy generated for "green pricing" programs could count toward the REO, and found that such energy would not be allowed to count toward a utility's RPS. The Commission affirmed its June 1 Order in all other respects. The Commission anticipates issuing notices and requesting additional comments on several remaining issues, such as reporting requirements, including content, timing, and related issues, voluntary compliance or reporting by municipal utilities, and specific criteria and standards applicable to Xcel. In 2002, renewable resources accounted for 5.5%, and non-hydro renewables, 3.9%, of total generation in Minnesota.[138]

PENALTIES ONLY

<u>California</u>

Legal Foundation

66. In California, the RPS is scheduled to increase annually by at least 1% and to reach at least 20% by 2017. The California Public Utilities Commission ("CPUC") and the California Energy Commission ("CEC") are collaboratively implementing California's RPS. The CPUC has to determine a "referent" market price of electricity from renewable resources, establish an annual least-cost and best-fit procurement process for electricity retailers, impose penalties in the event an electricity retailer fails to meet renewable resource procurement targets, and establish standard terms and conditions for renewable resource contracts. The CEC has to certify eligible renewable resources, design and implement an accounting system for verifying compliance, and allocate and award supplemental energy payments.[139]

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135 *See* Minnesota Public Utilities Commission, *Staff Briefing Papers for E-999/CI-03-869*, September 21, 2004 available at http://www.puc.state.mn.us/ last visited on January 27, 2005.

136 *Ibid.*

137 *Ibid*.

138 *Supra* Note 33.

139 *See* California Senate Bill 1078, Chapter 516, at 1-2, and 11.

- Contract costs equaling the referent price are recovered from retail rates. Contract costs exceeding the referent price are recovered through supplemental energy payments from the New Renewable Resources Account ("NRRA") of the Renewable Resource Trust Fund ("RRTF"). Claims for supplemental energy payments are required to be just and reasonable. Supplemental energy payments are made directly to the renewable resource provider rather than to the electricity retailer, and are limited by the availability of NRRA funds.[140]

- If an electricity retailer fails to meet the RPS target in a particular year, it is required to procure additional renewable resources in subsequent years, as long as NRRA funds are available. If supplemental energy payments are insufficient, then the electricity retailer may be allowed to limit its annual procurement to the available amount of supplemental energy payments.[141]

- The cost of the RPS is recovered from retail generation rates and from supplemental energy payments. Indirect costs associated with the purchase of renewable resources, such as imbalance energy charges, sale of excess energy, or transmission upgrades, are not eligible for supplemental energy payments but can be recovered from retail rates, as authorized by the CEC. The RRTF, the source of supplemental energy payments, is funded by a non-by passable charge.[142]

Implementation

67. California, a recognized leader in renewable energy development, obtained approximately 11% of its total electricity production from renewable resources in 2001. California is home to three of the largest developed wind resource areas in the world, produces the largest amount of electricity from concentrating solar power facilities in the world, and is the third largest market for PV energy after Germany and Japan.[143] California also has hydro and geothermal resources that other states do not have. According to the CEC, trends in renewable electricity generation suggest that the RPS is economically feasible,[144] many renewable technologies are close to cost parity with conventional sources, and renewable costs have been declining and may fall further.[145]

68. On May 8, 2003, the CEC, the CPUC, and the California Power Authority adopted an Energy Action Plan that accelerates the RPS to reach the 20% target by 2010 instead of 2017. On September 25, 2004, however, the Governor vetoed Assembly Bill 2006 that would have required the accelerated

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140 *Ibid* at 9-10.

141 *Ibid* at 11.

142 *Supra* Note 139 at 3 and 10. See also California Senate Bill 1038, Chapter 515, at 1 for the non-by passable local distribution charge based on usage.

143 *See* California Energy Commission, *Renewable Resources Development Report*, 500-03-080F, November 2003.

144 *Ibid.*

145 *Ibid.*

schedule legislatively.[146] In April 2004, the CPUC issued an Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development to better track RPS compliance.[147] The rulemaking, in enabling the first round of RPS solicitations, set out to complete certain tasks, such as quantifying the amount of renewable generation in each utility's present portfolio, establishing annual procurement targets for each utility, adopting standardized contract terms and conditions, including the definition of a REC, finalizing the Market Price Referent methodology, and further developing the least-cost and best-fit evaluation process.

69. Possibly in early 2005, the CEC plans to adopt refinements to the RPS implementation guidelines, and to begin certifying facilities that are eligible for the RPS. Utilities expect to hold their first formal RPS solicitation under the adopted rules and guidelines. The CEC is expected to continue working collaboratively with the CPUC to resolve outstanding RPS implementation issues.

70. On December 16, 2004, the CEC adopted a decision that directs the major state utilities to procure the maximum feasible amount of renewable energy in general solicitations, and allows them to credit the procurement towards their RPS targets.[148] The decision also states that allowing a utility to meet its RPS Annual Procurement Target via an all-source request for offers and an RPS-specific solicitation is consistent with the Legislature's intention of integrating renewable procurement as closely as possible with general utility procurement practices. Moreover, the CEC, over the next long-term procurement plan cycle, plans to embed fully the RPS into long-term planning, and to make renewable energy development a central part of the utilities' resource planning efforts. In 2002, non-hydro renewable resources accounted for 12.9% of total generation in California.[149]

F. States With Neither REC Trading, Compliance Fees, Nor Penalties

<u>Illinois</u>

Legal Foundation and Implementation

71. In Illinois, legislation adopted a statewide renewable energy goal of increasing the share of renewable resources to total energy from 5% by 2010 to 15% by 2020.[150] It also authorized up to $500 million of new state revenue bonding to support the development of technologies for wind, biomass, and solar.

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[146] *See* http://www.governor.ca.gov/ last visited on January 31, 2005.

[147] *See* Public Utilities Commission of the State of California, *Order Instituting Rulemaking to Implement the California Renewables Portfolio Standard Program*, R.04-04-026, April 22, 2004 available at http://www.cpuc.ca.gov/ last visited on February 1, 2005.

[148] *See* California Public Utilities Commission, *PG&E, SCE and SDG&E's Long Term Procurement Plans (Adopted)*, Decision 04-12-048, December 16, 2004 available at http://www.cpuc.ca.gov/ last visited on January 28, 2005.

[149] *Supra* Note 33.

[150] *See* Illinois Compiled Statutes, § 20 ILCS 688/5.

However, it does not provide for an implementation schedule, compliance verification, or REC trading.[151]

<u>Iowa</u>

Legal Foundation

72. Iowa has a RPS/SA requiring its two investor-owned utilities, Mid-American and Interstate Power and Light, to purchase each year beginning January 1, 1990 a shared total of 105 MW of their generation from renewable resources. The 105 MW are divided according to each utility's share of total Iowa retail peak demand. The Iowa Utilities Board ("IUB") may increase a utility's required purchases if the utility exceeds its 1990 Iowa retail peak demand by 20% and if the extra purchase can encourage alternative energy production or small hydro facilities. The increase, however, is not to exceed the product of the utility's peak demand and the ratio of the utility's share of the 105 MW to its 1990 Iowa retail peak demand.[152] Capacity purchased from alternative energy production or small hydro facilities is excluded from a calculation of a utility's excess generating capacity for ratemaking purposes.[153]

- The IUB may require utilities to contract, purchase, or wheel energy from alternative energy production or small hydro facilities under terms and conditions that are not only just and economically reasonable to the utility's ratepayers but also non-discriminatory to alternative energy or small hydro producers. Rates are to be established at levels sufficient to stimulate alternative energy production and small hydro facilities in Iowa and to encourage the continuation of their existing capacity.[154]

- The IUB may adopt individual or uniform statewide utility rates. The IUB is to consider several factors in setting individual or uniform rates, such as the estimated capital cost of the next generating plant, contract terms between the utility and the seller, levelized annual carrying charge associated with the contract and the utility's construction program, the utility's annual energy costs, environmental and economic factors, among others. If the IUB adopts uniform statewide rates, it is to use representative data in lieu of utility specific information in applying the factors mentioned above.[155]

Implementation

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[151] *Ibid.*

[152] *See* the 2001 Code of Iowa, §476.44. See http://www.eia.doe.gov/ last visited on January 11, 2005 for DOE data showing that the capacity of renewable energy resources in Iowa is 529 MW in 2002.

[153] *Ibid* at § 476.45.

[154] *Ibid* at § 476.43.

[155] *Ibid.*

73. By requiring investor-owned utilities to meet the 105 MW mandate through the purchase of renewable energy from other sources, past legislation sought to promote renewable energy generation from small independent companies and groups. However, the so-called small-producer incentive was largely ineffective since large non-Iowa companies own most facilities currently producing the 105 MW.[156] Thus, in 2003, Iowa passed legislation allowing investor-owned utilities to own alternative energy facilities whose output counts toward the company's share of Iowa's 105 MW renewable energy requirements.[157]

74. Iowa is on track to realize a goal of 1,000 MW of renewable energy by 2010, even though it has not been mandated legislatively.[158] Iowa currently has 580 MW of renewable generation.[159] Of the 580 MW total, 80 MW of wind is for meeting Wisconsin renewable requirements, and 125 MW from a Mississippi River hydropower facility is owned by a non-Iowa utility. An additional 44 MW is under construction, and 310 MW is scheduled for 2005 or 2006. The planned plants add up to a projected total of 934 MW of renewable energy by 2007.

75. There could be several reasons why Iowa has made significant progress in the establishment of renewable energy capacity. Iowa is the 10th windiest state in the U.S., and nearly 40% of its land area has wind generation potential.[160] In Iowa, wind power currently costs between $0.04/kWh and $0.05/kWh, which makes it broadly competitive with traditional generation resources.[161] Iowa has gained strong support from its schools and other public institutions, including the Iowa Department of Economic Development, which has contributed to the funding of wind projects. Finally, as mentioned above, 80 MW of wind generation is for Wisconsin, and 125 MW is a Mississippi River hydropower facility owned by a non-Iowa utility.

<u>New York</u>

Legal Foundation

76. In New York, the RPS is scheduled by 2013 to reach 25% consisting of a mandatory component of 24% achieved through policy and a voluntary component of 1% achieved through voluntary green market programs of utilities. The New York State Energy Research and Development Association ("NYSERDA") serves as a central procurement authority that receives all funds collected by utilities for

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[156] *See* Governor's Energy Policy Task Force, *Recommendations for New Energy Policy for Iowa*, October 2001, at 14.

[157] *See* State of Iowa, *House File 659*, April 11, 2003 available at http://www.legis.state.ia.us/ last visited on January 28, 2005.

[158] Iowa Utilities Board, Status of Recommendations from the 2001 Energy Policy Task Force Report to the Governor, December 17, 2003 available at http://www.state.ia.us/ last visited on January 28, 2005.

[159] *Ibid.*

[160] *See* State of Iowa, Department of Natural Resources, Renewable Energy Resource Guide, 2002 at 13.

[161] *Ibid*.

the RPS and administers incentives to providers in order to achieve the RPS targets for each year. NYSERDA funds are recovered from non-by passable volumetric delivery charges on customers.[162]

- There are two types of eligible renewable energy resources. The Main Tier consists of medium to large-scale generation facilities that are expected to compete against each other on a $/kWh basis for RPS funding. The Customer-sited Tier consists of "behind-the-meter" facilities that are generally not competitive with Main Tier technologies.[163]

- Central procurement is viewed as a way of expediting the start of the RPS and providing immediate feedback and control of the initial procurements. NYSERDA plans to transition eventually from central procurement to a market-based system that includes competitive energy providers and any related enforcement mechanisms.[164]

Implementation

77. The New York Commission issued an order establishing a renewable portfolio standard effective September 24, 2004.[165] The goal of the order was to increase the current 2005 projection of 19.29% of the renewable source energy retailed in New York to an overall policy goal of 25% by 2013. The increase is from a combination of a non-regulatory incentive-based program and green market programs. The bulk of the increase in renewable energy from 19.29% to 24% is from an incentives-based program administered by NYSERDA. Revenues for the program are from a volumetric delivery charge on electricity customers that is expected to begin in the fourth quarter of 2005.

78. The municipal-owned Long Island Power Authority and the New York Power Authority are not subject to the New York Commission and are not obligated to adhere to the RPS. The New York Commission strongly encourages participation in the RPS program and the NYSERDA administration of RPS funds. In 2009, the New York Commission plans to review NYSERDA plans to transition to a market-based approach to developing renewable energy resources. It recommends a trading system to enable the trade of RECs. However, it did not specify the design of such a system. In 2002, renewable resources accounted for 19.8%, and non-hydro renewables, 1.9%, of total generation in New York.[166]

G. Comparing Hawaii to Other States

Legal Foundation: RPS Components

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[162] *See* Order Regarding Retail Renewable Portfolio Standard, Case 03-E-0188, State of New York, Public Service Commission, September 24, 2004, at 3-4

[163] *Ibid* at 7.

[164] *Ibid* at 10.

[165] *See* New York Public Service Commission, *Order Regarding Retail Renewable Portfolio Standard*, September 24, 2004 available at http://www3.dps.state.ny.us/ last visited on January 28, 2005.

[166] *Supra* Note 33.

79. Hawaii, like other states, allows a variety of renewable energy resources that are eligible for satisfying the RPS. Three types of renewable energy resources are typically included in the renewable energy initiatives of the 22 states. The first is a central generation station, such as a biomass or wind plant, that is usually large and connected to the transmission system. The second is a decentralized facility, such as small hydro units, solar units, or sea water air conditioning units, which are typically located on a customer's premises. The third is a program, such as demand-side management or energy saving from solar water heating, which reduces demand for electrical energy.[167] Hawaii allows for all three types of renewable energy resources. The various renewable energy resources that can potentially be used in Hawaii are discussed in Part III of this paper.

80. Hawaii, like most other states, does not distinguish between one type of renewable energy resource and another in the satisfaction of the RPS. Colorado, Connecticut, Maryland, New Jersey, New York, Pennsylvania, and Washington D.C. have tiers or classes, and Colorado, Nevada, and New Mexico apply different weights to various renewable energy resources.

81. Hawaii, like other states, provides for the possible reduction in the RPS requirement if the cost of renewable energy is excessive, or if factors beyond the control of the utility are preventing compliance. Nevada, New Mexico, Pennsylvania, and Vermont have flexible requirements in the event of excessive costs, and Montana, New Jersey, New Mexico, Pennsylvania, and Texas allow for factors beyond reasonable control.

82. Hawaii, like all other states except New York, follows a decentralized approach to the procurement of renewable energy resources. Utilities are free to contract as they see fit, and any procurement cost exceeding a pre-determined market price is typically disallowed from rate base recovery. By contrast, New York uses a central procurement approach. A central agency purchases renewable resources on behalf of utilities that provide the funds for procurement. In the future, however, New York expects to transition to decentralized procurement.

83. Hawaii, like Connecticut, stipulates a ceiling on the price of renewable energy contracts that utilities may sign. Hawaii caps the rate paid to a renewable energy generator at 100% of avoided cost. The cap limits the cost of the RPS to the cost, net of retirements, of the next best plants that would have been added to the generation mix if there were no RPS. Connecticut caps price of long-term contracts for projects supported by Connecticut's Renewable Energy Investment Fund at the sum of the comparable wholesale market price for generation and $0.055/kWh.

84. Arizona, California, Connecticut, Massachusetts, and New York have customer charges, in the form of so-called system benefit charges or environmental charges, for covering the cost of the program. Arizona has different charges for various customer classes. California imposes a non-by passable charge. Connecticut has a renewable energy investment charge and system benefit charge that are both recovered through the rate base. Massachusetts applies a system benefit charge that is also included in the rate base. And New York has a non-by passable volumetric charge on customers.

[167] According to Jim Lazar, *Comments of Jim Lazar, Consulting Economist (Utility Rate Design Concept Paper)*, November 15, 2004, at 3, "new structures in Hawaii could be 20% - 50% more energy efficient with the application of available technology."

85. The diversity of eligible renewable energy resources could encourage investments in a wide range of technologies and reduce unnecessary barriers to investments. The absence of different weights applied to various renewable energy resources is likely to promote a renewable energy configuration that is based on the economic, financial, and geographical considerations of the islands of Hawaii. The provision allowing reductions in the RPS requirement if the cost of renewable energy is excessive, or if factors beyond the control of the utility are preventing compliance, provides incentives for utilities to procure renewable energy resources at the optimal scale, timing, and location. The decentralized market-driven procurement of renewable resources is expected to yield optimal decisions that benefit from the commercial information that is likely to be in the possession of dispersed economic agents. And the cap on the rate paid to a renewable energy generator, at 100% of avoided cost, may limit the cost of the RPS to the cost of the additional plants without the RPS. One implication is that, by design, the RPS program in Hawaii, unlike in other states, is unlikely to be a cause of an increase in retail rates in the future.

Legal Foundation: IR Mechanisms

86. Hawaii, unlike most other states with RPS, requires the regulator, the Commission, to explore the prospects of using alternative regulatory regimes, such as PBR, in implementing the RPS. The vast majority of programs, in 14 of the 22 states, allow utilities to recover the additional cost of the RPS from retail rates (see Table C2 in Appendix C). Although RPS programs in several states use cost recovery mechanisms that have strong IR influences, the RPS of Hawaii, apart from the ones of Colorado and Vermont, expressly advocates the use of alternative regulatory regimes, such as PBR, in the context of RPS implementation.[168]

87. One of the most popular IR mechanisms across the various states is the creation of RECs and corresponding market systems facilitating their trade (see Table C2 in Appendix C). The vast majority of programs, in 17 of the 22 states, are using or planning to use a REC trading system. California is reported to be considering the establishment of one. New York, which has a central procurement agency, has no need for one at the moment.

88. Connecticut, Maryland, Massachusetts, Pennsylvania, Rhode Island, Vermont, and Washington D.C. have ACPs that may be paid in lieu of purchasing or contracting for renewable energy resources (see Table C2 in Appendix C). Typically the payments are adjusted for inflation and support a development fund promoting renewable resource investments. Connecticut, Massachusetts, and Rhode Island require a $/kWh payment upon failure to comply. Maryland imposes different compliance fees for various customer classes and types of renewable resources. Pennsylvania provides for a review of the renewable energy market in determining the compliance payment.

89. Another popular IR mechanism, utilized in 10 states, is the imposition of fines and penalties (see Table C2 in Appendix C). The Commission may consider a system of fines and penalties in implementing the RPS program of Hawaii. Maine and New Jersey include license revocation. Nevada, New Jersey, and

[168] According to Steven P. Golden, *Act 95 Workshops – November 22-23, 2004 – Initial Concept Paper*, November 15, 2004, at 2, "mainland incentive ratemaking precedent is geared to cost-cutting and financial rewards more than to incentives toward RPS compliance."

Rhode Island prohibit the recovery of fines from retail rates. New Jersey, which has retail competition, includes a prohibition on accepting new customers. Under the program in Rhode Island, no sanction or penalty may relieve an entity from liability for fulfilling any shortfall in compliance. Texas has a penalty system based on both a $/MWh fine and the average market value of RECs. Wisconsin has fines for both RPS violations and the submission of false or misleading information on renewable energy resources.

90. Colorado provides for bonus payments that are overtly IR in nature. If investments in renewable energy resources bring net economic benefits to customers, then the utility earns its most recent authorized rate of return plus a maximum bonus of 50% of the net economic benefit. The Vermont regulator may approve alternative forms of regulation for an electric company and may offer incentives for innovations and improved performance that advance state energy policy.

Implementation

91. Hawaii, like other states with RPS programs, is currently in the process of RPS implementation. The experience of RPS implementation in individual states from the date of enactment onwards may provide several lessons for RPS implementation in Hawaii.

92. Reviews may have to be periodic. Arizona and New Jersey reviewed their RPS percentages before approving their respective increases. In Hawaii, Act 95 allows a review of the RPS every five years.

93. RPS implementation may be integrated with various proceedings and other regulatory policies. California closely integrates renewable procurement with general utility procurement practices, and plans not only to embed fully the RPS into long-term planning but also to make renewable energy development a central part of utility resource planning efforts. Nevada plans to integrate its RPS with those in nearby states.

94. Compliance perceived to date seems to have been feasible in four states: Iowa, New Jersey, Texas, and Wisconsin. Among them, three states, New Jersey, Texas, and Wisconsin, have only a REC trading system and penalties. Iowa has neither a REC trading system, compliance fees, nor penalties.

- Through a confluence of favorable commercial conditions, Iowa, which has a RPS/SA, is on track to achieve its renewable energy project goals. New Jersey has actually increased its RPS targets beyond the ones specified in legislation. Texas, which has a RPS/SA, is perceived to have strong enforcement, including an automatic penalty, has added substantially to its renewable energy capacity since 2001, and is ahead of its MW capacity targets. Wisconsin, which has both a RPS/SA and a RPS, has achieved early compliance.

- One implication is that enforcement may have to be strong. In Hawaii, strong and fair enforcement could signal that a market for renewable energy resources is likely to enjoy regulatory support, and that protracted non-compliance is unlikely to be allowed.

95. Limited compliance perceived to date in four states, Arizona, Minnesota, Connecticut, and Nevada, may depend on various financial and regulatory factors. Among them, two states, Arizona and

Minnesota, have only a REC trading system. Connecticut has a REC trading system and compliance fees. Nevada has a REC trading system and penalties.

- Arizona, which has a RPS, and Minnesota, which has both a RPS/SA and a RPS-style policy, have been hindered apparently by a lack of financing. Connecticut exempted over 99% of load and has had weak enforcement, and as a result, its RPS may not have encouraged much renewable energy supply. Nevada has seemingly suffered from a lack of financing, has yet to impose penalties for non-compliance, and has granted all utility petitions for RPS waivers.

- One implication is that exemptions and waivers may have to be minimized. In Hawaii, the exemptions have not yet been made; under Act 95, a waiver may be granted only if the cost of compliance is deemed excessive.

H. IR Mechanisms Per State and Their Requirements

96. States with RPS can be grouped in five categories according to the IR mechanisms in their RPS statues (see table below). Most states adopting an IR mechanism for RPS implementation create a REC trading mechanism, and most states use more than one IR mechanism. Quite importantly, most states are in still the process of RPS implementation, and their success in providing incentives to meet the RPS, as yet, cannot be fully evaluated.

IR Mechanisms Per State

State	Initiative	Credit Trading	Compliance Fee	Penalties
Illinois	RPS-style	No	N/A	N/A
Iowa	RPS/SA	No	No	No
New York	RPS	No	No	No
California	RPS	No	No	Yes
Arizona	RPS	Yes	No	No
Colorado	RPS	Yes	No	No
Minnesota	RPS/SA	Yes	N/A	N/A
Maine	RPS	Yes	No	Yes
Montana	RPS	Yes	No	Yes
Nevada	RPS	Yes	No	Yes
New Jersey	RPS	Yes	No	Yes
New Mexico	RPS	Yes	No	Yes
Texas	RPS/SA	Yes	No	Yes
Wisconsin	RPS/SA	Yes	No	Yes
Connecticut	RPS	Yes	Yes	No
Maryland	RPS	Yes	Yes	No
Pennsylvania	RPS	Yes	Yes	No
Vermont	RPS-style	Yes	Yes	No
Washington DC	RPS	Yes	Yes	No
Massachusetts	RPS	Yes	Yes	Yes
Rhode Island	RPS	Yes	Yes	Yes

97. A first step in considering candidate IR mechanisms in the context of RPS implementation in Hawaii is to identify each mechanism's underlying requirements, which may be divided in two: characteristics of the legislative mandate, and characteristics of the market (see table below).

IR Mechanism Requirements

IR Mechanism	Legislative Mandate			Market	
	Definition of targets	Levy Powers	Allocation Powers	Continental States	Deregulation
Credit Trading	Flexible	No	No	Positive effect	Positive effect
Compliance Fee	Flexible	Yes	Yes	No effect	No effect
Penalties	Flexible/Rigid	Yes	Yes	No effect	No effect

98. The first and a necessary condition for the adoption of any of the three IR mechanisms is the presence of a legislative mandate that makes its usage possible. In allowing the usage of any IR mechanism, an RPS legislative mandate can be characterized in terms of the definition of the policy targets and the authority to institute and operate the IR mechanism.

99. The first defining characteristic of an RPS legislative mandate is how renewable energy target levels are defined. There can be two types of regime definitions: flexible and 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 of renewable energy in a particular year. For example, as discussed above, Massachusetts allows flexible compliance through "banked compliance," which grants the carrying over of excess compliance from one year to another.

100. Not all IR mechanisms require a flexible regime, but a flexible regime is a necessary condition for the use of a REC trading mechanism or compliance fee system. A REC trading mechanism, in essence, allows an electricity supplier to achieve its RPS requirement through the purchase of RECs, which may have been produced out-of-state or carried over from earlier years with excess compliance. The payment of compliance fees also implies flexible adherence to the goals. In both a REC trading mechanism and a compliance fee system, the IR mechanism provides financial incentives to encourage renewable energy investments, but actual annual renewable energy generation may not correspond to the annual RPS target.

101. 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. A central feature of all three IR mechanisms is the introduction of financial incentives supporting investments in renewable power generation. However, not all three IR mechanisms require the regulator to collect or allocate funds. A REC trading mechanism relies on the creation of a market to set REC prices and to allocate resources of electricity suppliers or renewable energy developers. By contrast, a fee or penalty mechanism relies on the regulator (a) to determine the size of the levy it collects, either through a fee or a penalty, (b) to decide the manner of allocating the funds gathered from fee collections for investments in renewable energy generation projects, and (c) to identify the bona fide parties accessing the funds.

102. In addition to the necessary legislative backing, 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. Although these conditions are not typically as significant as the legislative mandate, they can affect the prospects for adopting a particular IR mechanism.

- First, consider whether or not the state's electricity markets are restructured. In a vertically integrated market, the utility has generation assets and is the local electricity supplier responsible for serving retail customers and for meeting the RPS requirements. An IR mechanism providing an incentive that encourages investments in renewable energy projects would be applied to the appropriate entity, which in this case is the utility, that has generation assets, serves retail load, and is tasked with achieving the RPS requirement. By contrast, in a restructured market, in which generation is owned by non-regulated utilities, IR mechanisms may have to be applied to distribution companies or load-serving entities.

- Second, consider the characteristics of the electric power market in the event a REC trading market is introduced. One common characteristic of all states in which REC trading markets have been adopted to date is that they are all continental states. As a consequence, they constitute a part of an integrated territory enabling the transmission of energy within and around the state. The creation of larger markets is significant because, in a well functioning market, a large number of buyers and sellers enhances the prospects of satisfying demand at competitive prices. For example, small states, such as Maine and Connecticut, have adopted REC trading but participate in the NEPOOL multi-state REC market.

103. An important component of RPS implementation is the definition of credible targets and strict enforcement. The arbitrary granting of waivers or exemptions from penalties is likely to undermine the success of RPS implementation. However, the incorporation of safeguards that ensure the consistency of the RPS with its legislatively mandated or supported goals must not be confused with loose or weak implementation.

104. Provisions aimed at accounting for special circumstances serve as safeguards. Targets that do not account for factors that are beyond the control of the utility and render renewable energy resources too costly are, in essence, uneconomical. The granting of an exemption in such circumstances may not weaken RPS implementation because, by definition, they are unpredictable and properly coping with them seems improbable. As a consequence, an efficient utility has an incentive to keep up its effort of procuring renewable energy because it cannot expect that the RPS will not be enforced. Such provisions are found in the RPS of Hawaii, Montana, New Jersey, New Mexico, Pennsylvania, and Texas. RPS implementation in Texas, which is considered to have one of the most effective RPS, does not appear to be hindered by the presence of such provisions.

105. Another provision aimed at meeting the cost-effectiveness requirement grants exemptions to deviations from RPS targets if the cost of renewable energy is deemed excessive. For example, the Hawaii RPS legislative mandate aims to encourage the use of cost-effective renewable energy resources. Penalties therefore should not be imposed if targets are not reached because of the cost-effectiveness provision. Like Hawaii, Nevada, New Mexico, Pennsylvania, and Vermont have flexible requirements in the event of excessive costs.

I. Comments

106. Comments are welcome on the various issues discussed above:

- RPS in Hawaii and other states;
- Tiers or classes of renewable energy resources;
- Weights applied to different renewable energy resources in meeting the RPS;
- Centralized and decentralized procurement;
- Price ceilings on renewable energy resource contracts;
- REC trading system;
- Charges;
- Alternative compliance fees;
- Penalties and fines;
- IR mechanisms;
- Integration with other regulatory proceedings and periodic reviews;
- Exemptions;
- Waivers;
- Compliance;
- Limited compliance perceived to date;
- Legislative mandate; and
- Power market characteristics.

III. Renewable Energy Resources in Hawaii

A. Overview

107. The efficiency of converting renewable fuels to electric power has improved. For example, the average power output per unit area swept by a wind turbine rotor has increased from 600 kW/m^2 about 20 years ago to over 1,000 kW/m^2 at present.[169] Investments in renewable resource projects have become potentially attractive. Levelized costs, defined as the capital, financing, and operating costs of generating electricity from a resource per MWh, have decreased by at least 50%, and capital costs have fallen dramatically, especially for wind energy plants (see Table D1 in Appendix D). As a result, renewable energy resources, which typically have high capital costs, have improved their competitiveness, and the choices of viable technologies and their locations have expanded. Depending on the price of oil and the cost of financing, among others, renewable energy technologies now may be competitive with fossil-fired plants.

108. Wind technology is considered one of the most viable renewable energy resources in view of improvements in reliability and performance in recent decades. Major wind farms are currently operating in California and Texas, among other locations in the U.S. The levelized cost of wind energy has fallen from about $0.30/kWh in 1980 to a current estimate of $0.05/kWh.[170] The cost of energy of a pulverized coal plant is about $0.037/kWh, and a gas combined cycle plant, $0.035/kWh,[171] and assuming high gas prices, the levelized cost of energy from coal is between $0.033/kWh and $0.041/kWh, and that from gas, between $0.035/kWh and $0.045/kWh.[172] The potential volatility in wind energy output, due to the intermittent nature of wind, could be addressed through the establishment of wind project portfolio.[173]

109. Innovation has led to substantial cost reductions in solar energy over the past several years, and developments in nanotechnology and manufacturing efficiencies are expected significantly to increase the use of solar energy. However, in general, commercial availability of solar energy seems limited, and solar is unlikely to be as promising as wind or biomass. High initial capital costs of solar power projects appear to have adversely affected its competitiveness versus other renewable energy resources (see Table D1).[174]

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[169] *See* http://www.eere.energy.gov/ last visited on January 5, 2005.

[170] *Ibid*. For a view that the levelized cost of wind is expected to reach $0.04/kWh within a decade, see Datta, *Supra* Note 15 at 13.

[171] *See* http://www.osti.gov/ last visited on January 13, 2005.

[172] *See* University of Chicago, *The Economic Future of Nuclear Power*, August 2004, at 9-17.

[173] A portfolio of wind resources is reported to reduce the uncertainty associated with an individual wind facility by about 30%. According to Datta, *Supra* Note 15 at 15, "geographically distributing wind resources has the potential to reduce the variability of the portfolio output to such an extent that the portfolio is worthy of capacity credit." According to Lazar, *Supra* Note 167at 8, "extensive hourly simulation modeling of the Hawaii utilities…" teaches that "wind resources deserve a 'firm capacity credit' roughly equal to their annual capacity factors."

[174] *See* http://www.eere.energy.gov/ last visited on January 13, 2005.

110. Biomass, the largest source of U.S. renewable energy since 2000, seems to be the only renewable alternative for liquid transportation fuel. However, unlike coal generation technology, which is quite dependable and proven, the efficiency of biomass remains uncertain. Although the efficiency of biomass steam generation may exceed 40%, actual plant efficiencies are only in the range of 20%.[175] As a result, co-firing, or the substitution of biomass for a portion of coal in an existing power plant, has been adopted as an economic short-term option for introducing new biomass power generation. Modular biomass systems using similar technology are under development and may provide additional opportunities for power generation. And as the cost of gasification and fuel cell systems continue to decline, they are likely to be coupled in future applications.[176]

B. Approach in Hawaii

111. Although less than 10% of Hawaii's generation and plant capacity is from renewable energy, the state currently has a wide range of renewable energy resources, such as biomass, geothermal, hydro, wind, and solar,[177] and the technical prospects seem promising.[178] Nevertheless, "some elements of location cost may be similar between islands while others may be unique to each island."[179] For example, the island of Kauai does not have geothermal and wood resources, and the siting of new generation on a small island, regardless of technology, remains a challenge.[180] Moreover, capital costs in Hawaii may be more than thrice the ones in the mainland.[181]

112. Much research has apparently been done on potential investments in renewable energy in Hawaii, and data and information assembled through previous research could be used as a starting point for identifying key operational and financial features, such as location, cost estimates, and performance attributes, of candidate projects in Hawaii. Three documents, HECO's Integrated Resource Plan ("HIRP"), a study conducted by Global Energy Concepts ("GEC") for the Hawaii Department of Business, Economic Development, and Tourism, and a study conducted by WSB-Hawaii ("WSB") in support of the Hawaii Energy Policy Forum, provide initial data and information on potential renewable energy projects in Hawaii.

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[175] *Ibid.*

[176] *Ibid.*

[177] *See* http://www.state.hi.us/ last visited on January 5, 2005.

[178] According to Datta, *Supra* Note 15 at 10, the "technical potential" of renewable energy in Hawaii is "over 3.5 million MWh or 25-28% of total projected demand by 2018."

[179] *See* Joseph McCawley, *KIUC Comments on PUC workshop concept paper*, November 15, 2004, at 1.

[180] *See* Nakazawa, *Supra* Note 20 at 2. The island, nevertheless, is exploring various power generation technologies, such as agricultural, municipal solid, and private haulers' waste.

[181] According to Lazar, *Supra* Note 167 at 4, "while new combined-cycle generators on the mainland are routinely developed for less than $700/kw, in Hawaii costs of as much as $2,500/kw are projected (for MECO)."

113. Apart from projects specifically identified in previous studies, archetypal renewable projects may be considered as candidate projects. For example, for a given technology, there are a variety of ways to consider alternative plant sizes, locations, and year of entry, among other project characteristics. The candidate projects potentially located in the various islands in Hawaii[182] are then used in the planned simulations of power production in order to determine the optimal timing, scale, and location of renewable resources satisfying the RPS of Hawaii. The expected results of the planned simulations are inputs to the formulation of candidate electric utility ratemaking structures. They do not constitute an endorsement or a rejection of specific technologies, plant sizes, locations, years of entry, or other project characteristics, and are not intended to replace or supercede the IRP process.

C. Candidate Renewable Resources

114. Kamaoa Wind Farm, a wind facility, is located at South Point on the island of Hawaii. It is owned by Apollo Energy Corporation and has a capacity of 9.3 MW that, at the moment, is derated to 6 MW.[183] Several wind projects ranging from 3 MW to 80 MW are under consideration at various locations throughout Hawaii (see Table D2).

115. Wind projects that are potentially viable are on the islands of Hawaii, Kauai, Maui, and Oahu. Capital costs are estimated to range from about $1,200/kW for small projects to over $2,000/kW for large ones. Operating costs, which are a fraction of capital costs, range from $50,000/year to just over $1M/year. The average cost of wind energy is expected to lie between $0.043/kWh and $0.078/kWh.

116. Solar energy is commonly used in dwellings in Hawaii. Solar water heaters serve an estimated 80,000 single-family homes, multi-unit dwellings, and institutional facilities in Hawaii.[184] More than 500 private homes and farms in the state use solar systems for some or all of their electrical needs.[185] PV provides electricity for a number of remote communication systems and scientific monitoring equipment. Hawaii has the world's largest hybrid solar-wind power system, which has a solar energy capacity of 175 kW and a wind energy capacity of 50 kW.[186] Several solar projects ranging from 0.10 MW to 50 MW are under consideration at various locations throughout Hawaii (see Table D3).

117. PV projects that are potentially viable are on the islands of Hawaii and Oahu, while parabolic trough systems that are potentially viable are on the islands of Hawaii, Oahu, Maui, and Kauai. In the absence of meaningful data, cost comparisons are difficult to perform. Capital costs for a potential 5 MW Fixed PV project are approximately $5,000/kW, but capital costs for much smaller 100 kW Fixed

[182] For a contention that "…it is not reasonable to develop a state-wide, 'one size fits all' plan since the electric utility systems serving customers on each of the Hawaiian islands are not interconnected and are unique systems," see Cheryl S. Kikuta, *Act 95 Workshops – November 22, 23, 2004 – Initial Concept Paper*, November 17, 2004, at 2 and 3.

[183] *Supra* Note 177.

[184] *Ibid.* According to Lazar, *Supra* Note 167 at 4, "while the cost of installing a solar water heater is higher in Hawaii, the size of water heater needed is smaller, due to the higher inlet water temperature."

[185] *Supra* Note 177.

[186] *Supra* Note 174.

PV and Tracking PV projects are around $10,000/kW. The cost of solar energy from parabolic trough systems is estimated to be $0.077/kWh, while the cost of energy from fixed PV systems is estimated to be more than $0.20/kWh.

118. H-POWER, a biomass facility, is located in Oahu, and Puna Geothermal Venture, a geothermal facility, is in the island of Hawaii. A few biomass, geothermal, and hydro projects ranging from 6.6 MW to 30 MW are under consideration at various locations throughout Hawaii (see Table D4).

119. Two candidate biomass projects are in Barber's Point and Waialua in Oahu. A candidate geothermal facility, 10 MW in capacity, is in Kilauea in the island of Hawaii. There are two candidate hydro projects: a 13.8 MW plant in Umauma Stream in the island of Hawaii and a 6.6 MW plant in Wailua River in Kauai. Capital costs for these projects range from a low of $2,208/kW for the Umauma Stream project to a high of $6,948/kW for the biomass facility at Barber's Point. Operating costs for the two hydroelectric facilities and the biomass project in Hawaii are estimated to be well under $1 million/year, while those for the geothermal plant and the biomass facility at Waialua are about $6 million/year. The cost of biomass, geothermal, and hydroelectric energy is estimated to range from $0.051/kWh to $0.101/kWh.

120. Remote or off-grid technologies, such as sea water air conditioning ("SWAC") and commercial/residential PV, may be considered as candidate projects. Off-grid technologies typically have the effect of reducing load in a particular area and therefore may be included in the planned power market simulations as load reduction. At the moment, there is no specific location for candidate SWAC facilities, which in principle can be sited in a flexible manner.[187] New or incremental energy efficiency projects, such as demand-side management or SWAC, may be considered as eligible renewable energy under Act 95.[188]

D. Comments

121. Comments are welcome on the various issues discussed above:

- Wind;
- Solar;
- Biomass;
- Geothermal;
- Hydro;

[187] For a suggestion that energy efficiency "must come first before considering the application of renewable energy technologies," and that cost savings from energy efficiency can be used to pay for the premium associated with renewable energy, see Arun Jhaveri, *Letter to Catherine Awakuni and Eileen Yoshinaka*, November 17, 2004.

[188] *See* Ken Costello, *Renewable Energy and Incentives*, Submitted to the Commission, January 27, 2005, at 2.

- Energy efficiency;
- Combined heat and power; and
- Other technologies.

IV. Proposed Elements of Ratemaking Structure and Incentive Regulation

A. Overview

122. As mentioned in Part I above, the conclusions emerging from the analysis may be used by the Commission to formulate rules establishing a ratemaking structure that can be adopted in a conventional rulemaking process, and the formally adopted rules can be used to implement the RPS.

123. RPS implementation proposals identified in Sections C and D below are in the nature of suggestions for review and discussion, and are subject not only to further discussion in future workshops but also to further review on an on-going basis.

B. Possible Goals of the Commission

124. The Commission, through the formulation of electric utility ratemaking structures, may pursue several goals in the implementation of Act 95.

- Market incentives may be provided to bring prices close to costs, reduce costs to their lowest possible level for a given output, and encourage prudent energy usage.

- Act 95 may be implemented in a flexible manner, to the extent allowed by law.[189] The pace and scope of RPS implementation, either increasing or decreasing the percentage, or advancing or pushing back the compliance year, as technological change occurs or as market participants respond, could be adjusted to the extent the achievement of the RPS, as provided in Act 95, is cost effective.[190]

- The development of renewable energy technologies may be promoted through the pressures of market forces and regulatory policy. The profit motive of utilities may be harnessed to achieve the RPS through the establishment of a market environment that is conducive to the attraction of capital financing utility investments, and in which utility owners earn competitive returns on their investment. The exercise of market power potentially causing uneconomic monetary transfers from customers to utility owners may have to be mitigated.

125. The efficiency and efficacy of RPS, RPS-style policies, or RPS/SA policies nationwide are likely to be empirical matters. Whether or not one IR mechanism is more efficient than another, or whether or not IR is more efficient than rate-of-return regulation, is likely to be an empirical matter. The Commission is advised not to propose a comprehensive revamp of the existing ratemaking structure.[191]

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[189] HRS § 269-95 (4) provides that the Commission shall "[r]evise the standards based on the best information available at the time if the results of studies conflict with the renewable portfolio standards established by section 269-92[.]"

[190] *See* HRS § 269-92 and 269-95 (1).

[191] "[A] new ratemaking structure might be a specific mechanism rather than an overhaul of the whole existing cost-base ratemaking structure," see Freedman, *Act 95 Workshops – Comments on Initial Concept Paper*, November 15, 2004, at 1.

C. Candidate Components of RPS Implementation

126. During the 2005 Legislative session, the Commission sought only one amendment to the RPS law, namely, the removal of the provision that electric utility profit margins would not decrease. However, the legislature did not amend the law as requested, and the Commission is required to implement the law as written.[192]

127. The RPS may be treated as mandatory,[193] subject to the provision that the RPS can be met cost-effectively. A mandatory RPS allows the use of both penalties and rewards. A non-mandatory or voluntary RPS, by contrast, prevents the use of penalties.

128. A long-term perspective may be taken in implementing the RPS under the current cost-of-service or alternative regulatory regimes, and periodic reviews may be held.[194] A long time horizon can be used to analyze whether or not a renewable project is cost-effective. A renewable resource typically has a higher capital cost, but a lower operational cost, than a fossil fuel plant, and renewable energy resources, unlike fossil fuel plants, may have efficiencies that are manifested only in the long run. An excessively short time frame is likely to produce a bias against high capital cost-alternatives, such as renewable energy resources, that may need additional time for both long-run efficiencies to emerge and adequate capital recovery to be obtained.

129. The RPS law contains a broad definition of renewable energy resources[195] that are eligible under the RPS.[196] In the course of the planned simulations of power production, the broad definition of renewable energy under the RPS law may be used to determine (a) the optimal scale, timing, and location of renewable energy resources satisfying the RPS and (b) the appropriate incentives influencing their entry.[197]

130. The RPS may be integrated with other proceedings, such as IRP and rate cases, pending at the Commission. There is a perception that "…the IRP process is an ideal forum to address how each

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[192] According to Costello, *Supra* Note 188 at 2, Act 95 "imposes a difficult task for the Commission." According to Freedman, *Supra* Note 191 at 2, "Act 95 is certainly not one of those rare, well-crafted statutes…" and "poses some difficult challenges that must be resolved."

[193] For a view that "a utility would strive to meet a non-obligatory standard only if it expects to be financially as well off or better off by doing so," see *Supra* Note 188 at 8. For a view that "the RPS provisions of Act 95 are not mandatory unless assertively administered as such by the Commission," and that "Act 95 is widely perceived as a mandatory instrument," see *Supra* Note 191 at 3 and 5.

[194] For a suggestion to have periodic mid-course corrections or changes during RPS implementation, see Arun Jhaveri, *Letter to Eileen Yoshinaka*, November 9, 2004, at 2.

[195] *See* HRS § 269-91.

[196] According to Freedman, *Supra* Note 191 at 3, if the definition of eligible renewable energy is very broad, "it may be that the 2020 milestone has already been attained."

[197] *Ibid* at 4 for a view that some questions raised by Act 95 could be addressed before the planned simulations, and that "some can perhaps be informed by the results of the simulations."

electric utility can meet the RPS requirements set forth in Act 95."[198] The implementation of the RPS may be integrated with proceedings related to competitive procurement,[199] which could be an effective instrument for increasing the efficiency of investments in power generation. Finally, the "…appropriate rate design, incentives and penalties are generally best developed in conjunction with the review conducted in a rate proceeding."[200] RPS implementation, which is likely to affect utility decisions on renewable and non-renewable energy investments, is expected to work well within the IRP process. Incentives developed for the RPS are intended to be consistent with and supportive of an IRP.

131. The RPS may be integrated with some current ratemaking issues. The issues pertaining to the current structure of electric utility rates may be contentious. There appears to be a concern that "…Hawaii's electric rates do not reflect true class cost of service, due to interclass and intraclass cross subsidies."[201] The Commission is advised to "…consider the rate and fee design proposals by the County of Maui in Docket No. 03-0371, including … time-of-use block rates for commercial customers."[202] There seems to be several other current rate issues, such as inverted end-block pricing, vintage rates, hook-up fees, rolling baseline rates, and time-of-use blocks,[203] that may be considered in the course of RPS implementation, but are unlikely to be addressed comprehensively in the planned production simulations. Finally, there is a belief that "…the removal of the cross-subsidies and rate re-design could provide the necessary incentives…to generate significant non-utility investments in renewables."[204]

132. An approach to the calculation of avoided cost may have to be developed (see Appendix E on the issue of avoided cost calculation). Under Act 95, the rate paid to a renewable generator may not exceed 100% of avoided cost. Several states allow the flexible implementation of their RPS programs in the event of excessive costs that are typically determined by their regulatory commissions. Under Act 95, the Commission may have to compare a utility's procurement cost of renewable energy to avoided cost, and an approach to avoided cost calculation may have to be developed. The Commission is advised to obtain inputs from an on-going avoided cost docket, Docket No. 7310, on the calculation of avoided cost in Hawaii. The Commission is also advised to rely on a competitive procurement process that could play a key role in ensuring least-cost resource acquisition.

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[198] *Supra* Note 182 at 3.

[199] For an observation that "where RPS has been successful, the utilities have employed a competitive bidding process," see Warren S. Bollmeier II, *Preliminary Comments on the PUC Initial Concept Paper: Electric Utility Rate Design in Hawaii*, November 15, 2004, at 2.

[200] *Supra* Note 198 at 4.

[201] *See* Steven P. Golden, *Act 95 Workshops – November 22-23, 2004 – Initial Concept Paper*, November 15, 2004, at 2.

[202] *See* Kal Kobayashi, *Act 95 Workshops – Initial Concept Paper*, November 15, 2004.

[203] *Supra* Note 167 at 5 and 6.

[204] *See* Warren S. Bollmeier II, *Preliminary Comments on the PUC Initial Concept Paper: Electric Utility Rate Design in Hawaii*, November 15, 2004, at 3.

D. Proposed Candidate IR Mechanisms

133. IR mechanisms could be developed to promote, among others, efficient behavior of electric utilities, fair and just electric utility rates, and the timely and adequate revelation of truthful information. Thus far, seven candidate IR mechanisms have been developed and may be used in various combinations as inputs to the development of electric utility ratemaking structures under Hawaii's RPS. The first three, a REC trading system, alternative compliance fees, and penalties, are gathered from other RPS programs, and the last four are specially developed for Hawaii.

Candidate IR Mechanisms Gathered From Other RPS Programs

First candidate IR mechanism: REC trading system

134. RPS requirements can be defined in terms of RECs. One REC is typically equivalent to one MWh of electricity generated from a renewable resource. The first candidate IR mechanism, inspired by the RPS programs in other states, is a REC trading system. Under this mechanism, an electricity supplier may purchase REC in order to meet some or all of its RPS requirements. RECs may be purchased directly from renewable energy generators, indirectly from specialist brokers, or through purpose-built markets.

135. Renewable energy generators are granted RECs corresponding to their renewable energy generation. In this context, electricity generated from renewable resources may be viewed to consist of two distinct commodities: the electricity itself, and the "green" attributes associated with and unbundled from it. The "green" attributes of renewable energy may be traded independently as RECs embodying the "green" attributes of renewable energy. A renewable generator can be considered to have two income streams: one from renewable energy sales, and another from REC sales. In this way, RECs bring a revenue stream on top of renewable energy sales, and therefore provide additional incentives to renewable energy investments.

136. Because a REC trading mechanism allows an electricity supplier to procure RECs in any combination in order to meet its RPS requirements, the RPS would be satisfied in the most cost-effective manner.

- A vertically integrated electricity supplier has an incentive to minimize the cost of meeting its RPS requirements. If, for example, it decides to meet its RPS requirement solely through the generation of renewable energy and obtain the corresponding RECs, then an electricity supplier incurs the cost of generating a sufficient amount of renewable energy serving the load that corresponds to the RPS requirement. If, however, it decides to meet its RPS requirement solely through the purchase of RECs, then an electricity supplier incurs the cost of (a) purchasing RECs for meeting the RPS requirement, and (b) acquiring energy for serving the load that corresponds to the RPS requirement.
- In deciding between generating renewable energy, thereby obtaining the corresponding RECs, and purchasing RECs from independent generators, a vertically integrated electricity supplier has an incentive to select the least-cost combination of RECs, renewable energy, and non-renewable

energy, that optimally would satisfy the RPS requirement and serve the load corresponding to the RPS requirement.

137. RECs increase the flexibility of meeting the RPS. Electricity suppliers are motivated to procure the optimal combination of RECs traded in regional or state REC markets. Collectively electricity suppliers have incentives to meet the RPS requirement at the lowest total cost overall. Secondary markets for RECs may emerge and provide additional financial instruments for dealing with RPS compliance risk.

138. There are a couple of potential disadvantages of a statewide REC trading system in Hawaii. Firstly, consider one island that may have much of the renewable energy generation, but another island that may have little renewable energy generation but has purchased certificates. One possible result is that the first island may have little of any adverse environmental effects of fossil fuel-fired generation, but the second island may have much of any adverse environmental effects of fossil fuel-fired generation. Secondly, the HEI utilities and KIUC are the only two entities that are potential buyers of certificates. The potentially small number of participants may prevent the emergence of competitive outcomes in the REC market.

Second candidate IR mechanism: alternative compliance fees

139. The second candidate IR mechanism, inspired by the RPS programs in other states, is a system of alternative compliance fees. Utilities can meet the RPS through the payment of fees to a renewable energy development fund. The fee may be established on a per kWh basis. The fund may be earmarked to support investments in renewable energy projects, and specific rules may be formulated to identify both eligible projects and *bona fide* users of the fund, such as renewable energy developers seeking to invest in the power generation market in Hawaii.

140. To serve its load under the RPS requirement, a utility has a choice between acquiring renewable energy generation and paying the fees. It therefore has an incentive to select the cheaper of two options: the cost of the renewable energy acquisition, or the sum of the fees and the cost of replacement non-renewable energy required to serve its load under the RPS requirement. As a result, utilities that can acquire renewable energy in the cheapest way, relative to the fees and their cost of replacement energy, are encouraged to do so.

141. There could be several potential disadvantages of a compliance fee system.

- First, the payment of fees and their accumulation in a renewable energy development fund may not ensure the installation of renewable energy generation projects at the appropriate scale, timing, and location. Renewable energy developers would have to evaluate the risks and rewards of entering the market, and may be discouraged from entry for reasons that could be unrelated to the existence of the fund. In fact, the payment of fees by the utilities could be viewed as a signal that entry of renewable energy generation capacity may not be commercially sensible.

- Second, the creation and operation of a centralized development fund identifying and supporting eligible projects may be more costly than a market-based approach allowing profit-driven participants to make decentralized investment decisions.

- Third, the fee, if improperly designed, may have a weak link to the profit incentive that drives utility behavior affecting the prospects of satisfying the RPS.

- Fourth, the establishment and operation of a renewable energy investment fund may not be consistent with the RPS of Hawaii. Under the RPS of Hawaii, the Commission may provide incentives encouraging utilities to meet their RPS requirements. The financial support potentially available from a renewable energy investment fund may have to be given to independent power producers or entities other than utilities. Moreover, the RPS law may not provide the Commission with the authority to create and run an investment vehicle for renewable energy.

Third candidate IR mechanism: penalties

142. The third candidate IR mechanism, inspired by the RPS programs in other states, is a system of penalties. Utilities are charged a fine for energy generation that falls short of the RPS. The fine may be established on a per kWh basis.

- Penalties exceeding the compliance cost provide an incentive to comply with the RPS.[205] Penalties have been suggested to be swift, sure, and severe, subject to evaluation annually, and in place for at least a year.[206]

- To serve its load under the RPS requirement, a utility has a choice between acquiring renewable energy generation and paying the fine. It therefore has an incentive to select the cheaper of two options: the cost of the renewable energy acquisition, or the sum of the fine and the cost of replacement energy required to serve its load under the RPS requirement. As a result, utilities that can acquire renewable energy in the cheapest way, relative to the fines and their cost of replacement energy, are encouraged to do so.

143. There are two potential penalty schemes for Hawaii. One is a flat fine, such as one for $0.05/kWh, which can be administered inexpensively through automatic enforcement in each compliance period, and could be flexible through its integration with tradable REC banking. However, as a fixed value, it is static and may not reflect the cost to society. Another penalty scheme, which seems more efficient than a flat fine, is to charge the full total system cost of failing to install the marginal renewable resource. The cost-effective marginal renewable resource that should have been deployed but was not, for a given year, can be defined. A charge equivalent to the entire cost in ¢/kWh for each kWh that falls short of the RPS creates a powerful incentive for the utility to comply, but holds ratepayers harmless in the event of non-compliance.[207]

144. A related system is the application of a penalty of about 2% of the equity return of non-complying utilities, or the provision of a reward calculated in a similar manner. For example, a utility that

[205] According to Datta, *Supra* Note 15 at 31,"Most states that have penalties use financial penalties that are higher than the cost of compliance so that it is in the utility's interest to comply with the standard instead of trying to evade it."

[206] *Supra* Note 167 at 10.

[207] *See* Datta, *Supra* Note 15 at 31 and 32.

historically has been allowed a 10% return on equity could be allowed to earn 12% as a reward or 8% as a penalty.[208]

145. One potential disadvantage of a penalty system is that the payment of penalties may not ensure the satisfaction of the RPS. If, for example, the time frame for the application of penalties is unclear, then there is a risk that penalty payments, and the corresponding non-compliance, could persist in perpetuity. Another potential disadvantage is that the penalty, if improperly designed, may have a weak link to the profit incentive that drives utility behavior affecting the prospects of satisfying the RPS. A penalty that is either too high or too low may lead to over- or under-compliance, and either outcome could be costly to society.

Candidate IR Mechanisms Developed For Hawaii

Fourth candidate IR mechanism: the utility receives its own avoided cost estimate

146. The fourth candidate IR mechanism calls for the utility to provide an estimate of the avoided cost of its generation mix.[209] In each of the Hawaiian islands and over an adequate time horizon, the avoided cost estimate provided by the utility is the price at which a renewable energy resource, whether its own or from an independent developer, is paid. Renewable energy resources are added until the RPS is satisfied. The avoided cost calculation allows for all types of generation technologies. The methodology for calculating avoided cost can be determined from an avoided cost docket currently on-going in the Commission, or from the current approaches used by utilities in recent submissions to the Commission. The amount recovered from ratepayers depends on whether the utility's avoided cost estimate exceeds or falls short of the true cost of renewable energy development.

- Imagine the utility provides an artificially high estimate of avoided cost. As a result, renewable energy resources from independent developers, whose costs are possibly lower than the artificially high estimate of avoided cost, are likely to be encouraged. The utility is required to pay the independent developers the artificially high estimate of avoided cost, but can recover from ratepayers, through the rate case process, only the true low cost of the independent developers. The utility, therefore, is at risk for the difference, and foregoes an opportunity to expand its own renewable energy capacity.

- By contrast, imagine the utility provides an artificially low estimate of avoided cost. As a result, possibly few renewable energy resources from independent developers are likely to be encouraged. The utility's new renewable energy resources would probably be installed, but are paid the artificially low estimate of avoided cost. The utility can recover only the artificially low estimate of avoided cost, rather than the true cost, assuming they are unequal, from ratepayers. In

[208] *Supra* Note 167 at 10.

[209] According to Freedman, *Supra* Note 191 at 5, the Act 95 provision pertaining to avoided cost "essentially limits the effect of the statute to nothing more 'mandatory' than the preexisting status quo represented by federal and state codifications of PURPA and the Commission's Framework for Integrated Resource Planning," unless an alternative approach to the avoided cost calculation is used.

short, the utility could be restricted in obtaining adequate funds for its own renewable energy capacity expansion.

147. Under the fourth candidate IR mechanism, electric utility rates are likely to be fair and just. In the event of an artificially high estimate of avoided cost, ratepayers cover only the true cost of new renewable energy resources. In the event of an artificially low estimate of avoided cost, ratepayers cover only the artificially low price and therefore are shielded from the cost of the estimation error.

148. Under the fourth candidate IR mechanism, truthful information may be revealed in a timely and adequate manner. The utility may have the proper incentive to provide its best estimate of its avoided cost. The risk to the utility of providing an artificially high or low estimate, therefore, is great.

149. The application of the fourth candidate IR mechanism is likely to depend on a meaningful calculation of avoided cost.[210]

- Several sensible assumptions underlying the avoided cost calculation might have to be made, such as a reasonable distribution of power generation technologies and a time horizon that is adequately long. A reasonable distribution of power generation technologies decreases the likelihood that fossil fuel plants or renewable resources are either over- or under-represented in the sample of candidate projects.[211] A long time horizon could minimize the potential bias against high capital cost-alternatives, such as renewable energy resources, that may need additional time for long-run efficiencies to emerge and adequate capital recovery to be obtained.[212]

- One approach to the calculation of avoided cost is to integrate it with the utility's IRP. The utility may develop or contract for resources identified in its IRP, and the renewable resource identified in the approved IRP could not be avoided by installing conventional resources without amending the IRP. As a result, the costs avoided by the utility for implementing renewable resources would reflect the costs of the renewable resource in the utility IRP, and the Act 95 definition of "cost-effective" as "at or below avoided costs" is unlikely to prevent the achievement of the RPS.[213]

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[210] According to Costello, *Supra* Note 188 at 3, the measurement of avoided cost "was a major area of contention in regulatory proceedings over 20 years ago involving the implementation of PURPA at the state level." It seems to be still contentious until today.

[211] According to Datta, *Supra* Note 15 at 20, another advantage of having a reasonable distribution of generation technologies seems to be that the addition of renewable energy resources, which have low fuel risks, to a portfolio of fossil fuel plants "serves to reduce overall portfolio cost and risk, even though their stand-alone generating costs may be higher."

[212] According to Costello, *Supra* Note 188 at 11, "if prices are anticipated to decline, then … why electrical utilities haven't already exploited these opportunities … in the absence of RPS." One possible reason is that the time horizon used for evaluating investments in renewable energy projects may be inadequately short. Another possible reason is the fuel adjustment mechanism. According to Lazar, *Supra* Note 167 at 3, "Hawaii has a very generous fuel adjustment mechanism," "which tends to bias Hawaii utilities in favor of resources with low capital costs and high fuel costs, because the fixed costs are 'at risk' while the variable cost recovery is largely protected."

[213] *Supra* Note 191 at 7.

150. One possible disadvantage of the fourth candidate IR mechanism is that a utility may be motivated merely to satisfy, rather than to exceed, the RPS.[214] Merely satisfying the RPS appears to be consistent with the letter, but not the spirit, of Act 95. Another possible criticism is that the fourth candidate IR mechanism is unlikely to resolve the possible conflict between building a plant, which is an asset in financial statements, and signing a long-term contract, which functions as a debt-like obligation that possibly has an adverse effect on credit ratings.[215]

Fifth candidate IR mechanism: the utility receives a difference share

151. The fifth candidate IR mechanism calls for the Commission to produce, through a collaborative process, an estimate of avoided cost without the RPS. Under the fifth candidate IR mechanism, the Commission's avoided cost estimate becomes a benchmark for comparing the utility's cost of acquiring renewable energy resources.

- If the Commission's avoided cost estimate exceeds the renewable energy resource cost, then the utility is allowed to recover 50%, or some reasonable share, of the difference from ratepayers. The renewable energy resource may be installed through the additional cost-recovery until the RPS is satisfied.

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

- This mechanism can be viewed as a variant of the previous mechanism. Under this alternative, the utility keeps only part of the difference between the avoided cost and the renewable cost. This application is aimed at passing on to consumers not only the environmental gains but also part of the efficiencies that may be derived from renewable generation.

152. Under the fifth candidate IR mechanism, the utility may have an incentive to keep the cost of acquiring renewable energy resources as low as possible. It would have an incentive to engage in a rigorous search for the best available technology for renewable energy, or to increase the vigor of its negotiations with independent developers of renewable energy resources, in order to reduce the acquisition cost of renewable energy and therefore to increase the basis, if any, of its share.

153. Under the fifth candidate IR mechanism, electric utility rates are likely to be fair and just. The risk to ratepayers is capped at the Commission's avoided cost estimate, which would have been the cost to ratepayers in the absence of the RPS and would have been consistent with Act 95.

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[214] However, according to Costello, *Supra* Note 188 at 5, "it may be undesirable for a utility to exceed the standards if it results in higher costs to the utility and higher rate [sic] to customers."

[215] *Ibid* at 9. For a view that, "since utilities earn…on investments in their own generation…they have a disincentive to allow independently produced renewables…even if they are the least cost solution," see Datta, *Supra* Note 15 at 8. For a reminder that long-term power purchase agreements have implications for the balance sheet and credit worthiness of the utility, see William A. Bonnet, *Comments Relating to the RPS Initial Concept Paper*, November 15, 2004, at 3.

154. Under the fifth candidate IR mechanism, truthful information is likely to be revealed in a timely and adequate manner. If the utility does not keep the cost of acquiring renewable energy resources as low as possible, then it faces the risk of foregoing a payment. The utility has an incentive to find and to secure the best deal.

155. As in the fourth candidate IR mechanism, the application of the fifth candidate IR mechanism is likely to depend on the meaningful calculation of avoided cost. The sensible assumptions discussed as regards the avoided cost calculation under the fourth candidate IR mechanism could also apply to the one under the fifth candidate IR mechanism.

Sixth candidate IR mechanism: claw back of incremental utility profit

156. The sixth candidate IR mechanism calls for a dollar penalty that a utility would pay for non-compliance energy, and requires determinations that the RPS can be met in a cost-effective manner for each utility and that the Commission is to allow the recovery of all prudently incurred RPS costs. The dollar penalty has to be set at an efficient level. The efficient penalty for a utility is the cost to society of its not achieving the RPS. A penalty that significantly exceeds compliance costs[216] but has a weak link to the efficient penalty may unwittingly induce inefficient utility behavior.[217] One possible measure of the penalty is the incremental benefit to the utility of violating the RPS. The penalty, therefore, is derived from the revealed profit-maximizing behavior of the utilities, and may vary across different utilities and over time. A penalty that is excessively large or exceedingly small relative to the level required to alter a utility's profit-maximizing behavior may result in either over- or under-deterrence, which are both costly to society. Unlike the generic specification of penalties defined above, this mechanism proposes a penalty structure that is designed to be commensurate to the utilities' incentives not to comply with the RPS.

157. Under the sixth candidate IR mechanism, the utility may have an incentive to comply with the RPS even without new incentives. A utility would be motivated to estimate the opportunity cost of its actions.

- Imagine that complying is more profitable for the utility than violating. As a result, the utility may have an incentive to comply, and might actually comply. Extra steps may not be required to encourage compliance because the profit incentive may have motivated the utility to act in its best interest, which, in this case, is to comply.

- By contrast, imagine that complying is less profitable than violating. As a result, the utility may have an incentive to violate, and might actually violate. A penalty may have to be designed to minimize the incremental benefit from violating, subject to the regulatory condition that the utility

[216] For a view that the "penalty should exceed significantly the expected cost of compliance to give retailers a self-interest in full compliance," see Nancy Rader and Scott Hempling, *The Renewable Portfolio Standard (A Practical Guide)*, Prepared for NARUC, February 2001, at 74 and 75.

[217] According to Freedman, *Supra* Note 191 at 10, "the marginal attainment objectives must result in marginal changes in utility profits."

continues to have the opportunity to earn a reasonable rate of return. The penalty may have to be adjusted until compliance is in the utility's best interest, which, eventually, is to comply.

158. Under the sixth candidate IR mechanism, electric utility rates are likely to be fair and just. Ratepayers do not cover the penalty.

159. Under the sixth candidate IR mechanism, truthful information is likely to be revealed in a timely and adequate manner. The profit-maximizing behavior of the utility reveals not only its financial condition but also the net benefit of compliance or violation. If the utility complies, then compliance appears to be its current profit-maximizing decision. If it violates, then violation appears to be its current profit-maximizing decision, and the penalty may be adjusted until compliance becomes its optimal decision.

160. One possible disadvantage is that, as in the fourth candidate IR mechanism, the sixth candidate IR mechanism is unlikely to resolve the possible conflict between building a plant and signing a long-term contract.

Seventh candidate IR mechanism: the utility receives a payment based on a multiplier

161. A key aspect of the Commission's legislative mandate is to ensure that only cost-effective renewable sources of electricity are introduced. The goal of this seventh mechanism is to define a calculation of the cost of alternative sources of electricity that accounts for the broader economic cost of not adopting renewable energy to Hawaii. The seventh candidate IR mechanism is based on the concept of a multiplier effect. One key assumption is that each MWh of renewable energy displaces one MWh of the marginal technology, oil-fired generation. Given that about 80% of the power generation capacity in Hawaii is oil, it is likely that the marginal unit displaced by a renewable resource would be oil. Another key assumption is that the marginal unit displacement yields Hawaii an extra saving estimated as the price of imported oil. The oil that a renewable energy resource has displaced is likely to be imported, and the cash saved from the avoidance of the importation would remain in Hawaii. The saving feeds into the Hawaii economy and creates further rounds of spending. The cumulative impact on Hawaii of the initial saving is called a multiplier effect, and could be calculated as the product of the oil price and a multiplier. An independent analyst, such as a macroeconomist at the University of Hawaii, or the macroeconomics literature, may provide an estimate of the multiplier in Hawaii.

162. The seventh candidate IR mechanism calls for a comparison between the cost of the marginal generation technology, assumed to be oil, and the utility's cost of acquiring renewable energy resources, and the provision of a payment if it is necessary to encourage the utility to invest in the renewable energy resource.

- Imagine that the marginal generation technology, oil-fired, is cheaper than the renewable energy resource. But imagine, too, that the provision of a payment to the utility makes the renewable energy resource cheaper than the marginal generation technology. If these two conditions hold, then the payment may provide the utility an incentive to install the renewable energy resource. Under the seventh candidate IR mechanism, the utility is allowed to recover from ratepayers both the renewable energy resource cost and the payment defined as 50%, or some reasonable share, of the incremental benefit due to the multiplier effect.[218]

- If, however, 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 therefore no payment under this mechanism is provided.

163. Under the seventh candidate IR mechanism, electric utility rates are likely to be fair and just. The risk to ratepayers is capped at 100% of avoided cost or, under the seventh candidate IR mechanism, oil-fired generation cost, in the event the payment is not enough to make the renewable energy resource competitive to oil-fired generation.

164. Under the seventh candidate IR mechanism, truthful information is likely to be revealed in a timely and adequate manner. The payment to the utility for acquiring renewable energy is based on two objective and independent measures, the oil price, which can be observed, and the multiplier, which can be estimated, and both are beyond the control of any electricity market participant in Hawaii.

E. Recommendations

165. The seven candidate IR mechanisms reviewed below are in the nature of incentives that, if needed, are provided for utilities to comply with the RPS in Hawaii. They suggest approaches to ensure not only that compliance is achieved but also that the targets in terms of the percentage share of renewable generation in the generation mix are met by encouraging investments in renewable energy generation projects.

166. The seven candidate IR mechanisms should be reviewed in terms of the definition of the RPS target, the Commission's powers to levy a fee and allocate the proceeds, Hawaii's size, location, and proximity to other states, and the status of power sector deregulation in Hawaii.

167. The first candidate IR mechanism is the establishment of a REC trading system.

- The definition of the RPS target in terms of RECs adds flexibility to compliance. In particular, REC trading allows flexible RPS compliance in Hawaii through the carry over of excessive compliance or insufficient compliance from one year to another.

- In principle, REC trading can be implemented in Hawaii because it does not require a deregulated power market. It does not require the Commission to have levy powers, and relies on the REC market to set REC prices. And it does not require the Commission to have allocation powers, and relies on the REC market to allocate resources.

[218] Under the seventh candidate IR mechanism, the incremental benefit due to the multiplier effect may be estimated as the product of (a) the oil price and (b) the difference between the multiplier itself and one. The key assumption is that the multiplier exceeds one. There are several formulae for the multiplier, depending on the macroeconomic model used, and one common formula for the multiplier is 1/(1-MPC), in which MPC is the marginal propensity to consume. In macroeconomic theory, part of an increase in income is consumed, the rest is saved, and the MPC is defined as the increase in consumption induced by an increase in income.

- However, REC trading could have twin risks associated with Hawaii's size and location. Firstly, Hawaii is a small state, and the small size could limit the number of RECs available for trade. Secondly, Hawaii is a non-contiguous state, and the tendency of concentrating renewable energy generation in some islands may be worsened.

- The favorable consequences expected from the features of a REC trading market are likely to offset any unfavorable consequences possibly from the twin risks mentioned above. The Commission is advised to consider a REC trading market for further assessment.

168. The second candidate IR mechanism is the establishment of a compliance fee system.

- A compliance fee system allows flexible RPS compliance in Hawaii through a combination of compliance fee payment and actual renewable energy generation or REC equivalents. Moreover, it has little to do with the size of Hawaii, its location, or its proximity to other states, and does not require a deregulated power market.

- However, a compliance fee system requires the Commission to have levy powers for setting the compliance fee at a level that would provide sufficient incentives encouraging renewable energy generation. It also requires the Commission to have allocation powers for collecting fees, creating a fund, and investing.

- The positive features of a compliance fee system may be worth the potential effort for the Commission to acquire levy and allocation powers, if it does not possess such powers under Act 95. The Commission is advised to consider a compliance fee system for further assessment.

169. The third candidate IR mechanism is the establishment of a penalty system aimed at deterring non-compliance, and the sixth candidate IR mechanism, the claw back of incremental utility profit, may be interpreted as a specific approach to the calculation of the optimal penalty level.

- A penalty system does not require the Commission to have allocation powers for creating a fund from them, and investing. Moreover, it has little to do with the size of Hawaii, its location, or its proximity to other states, and does not require a deregulated power market.

- However, a penalty system does not allow the Commission to promote flexible RPS compliance in Hawaii. The payment of a penalty does not amount to compliance, especially if inadequate compliance can be carried over from one year to another. Moreover, a penalty system requires the Commission to have levy powers for setting the penalty at a level that would provide sufficient incentives encouraging renewable energy generation.

- The design of optimal penalties should account not only for their effects on a utility's conduct but also for their possible interaction with other incentive mechanisms, such as compliance fees. Moreover, an optimal penalty should be set at the level needed to accomplish the deterrent effect that it is supposed to achieve. The sixth candidate mechanism proposes an optimal penalty design based on the principle that the gain from compliance exceeds the gain from violation. Another approach to penalty design is to disallow, in the ordinary course of a rate case process, the recovery of non-renewable energy costs that the Commission could deem to have been imprudently incurred.

- The favorable consequences expected from the features of an adequately designed penalty system are likely to offset any unfavorable consequences possibly from the costs of inflexible compliance and the acquisition of levy powers for the Commission. The Commission is advised to consider an optimal penalty system for further assessment.

170. The fourth and fifth candidate IR mechanisms provide financial incentives for utilities to find the most cost effective approach to RPS compliance.

- The fourth and fifth candidate IR mechanisms allow flexible RPS compliance in Hawaii. They do not require the Commission to have levy powers; instead, they rely on the utility's response to the mechanisms in determining the level of the financial incentive, and work within the existing regulatory structure in providing a positive or negative financial incentive. They do not require the Commission to have allocation powers; instead, they rely on the utility to allocate its own resources. They have little to do with the size of Hawaii, its location, or its proximity to other states. And they do not require a deregulated power market.

- However, under the fourth and fifth candidate IR mechanisms, financial incentives for the provision of cheaper renewable energy come at the expense of potential cost savings that could be passed along to consumers. An optimal incentive design would account for this trade-off.

- The favorable consequences expected from the fourth and fifth candidate IR mechanisms seem to be substantial and worthy of consideration. The Commission is advised to consider the fourth and fifth candidate IR mechanisms, in which a utility receives its own avoided cost or a difference share, for further assessment.

171. The seventh candidate IR mechanism proposes to promote the introduction of renewable energy through financial incentives that take into account the broader economic costs of not adopting renewable energy in Hawaii.

- The seventh candidate IR mechanism allows flexible RPS compliance in Hawaii. It does not require the Commission to have levy powers; instead, it relies on observable variables in determining the level of the financial incentive, and works within the existing regulatory structure in providing a positive or negative financial incentive. It does not require the Commission to have allocation powers; instead, it relies on the utility to allocate its own resources. It has little to do with the size of Hawaii, its location, or its proximity to other states. And it does not require a deregulated power market.

- The favorable consequences expected from the seventh candidate IR mechanism seem to be substantial and worthy of consideration. The Commission is advised to consider the seventh candidate IR mechanisms providing payments based on the multiplier concept for further assessment.

F. Comments

172. Comments are welcome on the various issues discussed above:

- Candidate RPS components;
- Features of Act 95;
- The seven candidate IR mechanisms;
- Achieving the RPS;
- Fair and just electric utility rates; and
- The timely and adequate revelation of truthful information.

Appendix A: Rate-of-return and Incentive Regulation

Desirable Attributes of Rate Regulation

173. Regulation seeks to provide incentives. One of the most important incentives is price,[219] and one of the central activities of utility regulation is price setting or ratemaking. There are generally four functions of a utility price system: capital attraction, production efficiency, consumer rationing, and compensatory income transfer. Capital attraction pertains to the acquisition of financial resources supporting utility investments. Production efficiency pertains to ensuring least cost production. Consumer rationing pertains to encouraging prudent usage. Compensatory income transfer pertains to the profits accruing to the operators of the utility. These four functions may not always be in harmony in a regulated utility, and ratemaking often requires a wise compromise among them.[220]

174. Market power, a key issue in utility regulation, typically affects these four functions. Regulation mitigates market power in order to keep the risk-adjusted returns of a utility at competitive levels. Whether through legislation, regulation, or economic efficiency, a regulated utility often has some degree of market power. If regulation does not constrain prices, then a monopolist utility has an incentive to charge prices well above its long-run costs, and could transfer substantial wealth, representing economic rent, from customers to its owners. One of the major tasks of regulation is to minimize rent transfers, and to ensure that utility owners earn only competitive returns on their investment.

175. Capital formation refers to the need to attract financing for investments in utility infrastructure. Most regulated utilities are capital intensive and require substantial sums of capital to provide efficient services. For example, an efficiently sized coal-fired generation plant may cost $1 billion. Utilities have to earn sufficient revenues in order to finance such large investments. In addition, because utility assets are often long-lived, utility income streams have to be relatively secure in order to reduce risk to a level that investors are willing and able to bear. One of the major tasks of regulation is to ensure that utility capital formation is facilitated.

176. Production efficiency refers to whether or not a utility produces at the lowest possible average total cost. Prices that are set at average total production cost are not necessarily efficient or competitive if production costs are above their lowest possible level for a certain quantity and quality of services. Competitive markets ensure not only that prices are driven to cost, but also that costs are reduced to their lowest possible level for a given output. One of the major tasks of regulation is to ensure that costs are at the lowest possible levels.

177. Product allocation refers to the amount of services that customers typically purchase. If pricing is efficient and if external or network effects are absent, at least three efficient allocation conditions are

[219] According to Bonnet, *Supra* Note 215 at 3, "one of the objectives of increased reliance on renewable energy resources is increased price stability for electricity prices."

[220] *See* Bonbright, James C., A. L. Danielsen, and D. R. Kamerschen, *Principles of Public Utility Rates*, Public Utilities Reports, Inc. (1988), at 91-107.

likely to hold. First, the value of the service to a customer exceeds its production costs. Second, a customer who most desires the service would pay a greater share of common costs than one who does not have as strong a desire. And third, a group of customers would not pay a higher price than the level at which the customers could gather and provide the service themselves. One of the major tasks of regulation is to ensure that utility rates reflect efficient allocation conditions.

Rate-of-return and Incentive Regulation

178. The structure of regulation typically determines the nature and magnitude of the incentives faced by the utility. Rate regulation is implemented through tariff design, the choice of regulatory regime, and contractual obligations. Much of the literature on the choice of regulatory regime is on rate-of-return or cost-of-service regulation, which is the most widely used regulatory regime in the U.S. today. Under rate-of-return regulation, prices equal recoverable costs, including a reasonable return on investment.

179. Rate-of-return regulation historically has been used to achieve the functions of a utility price system discussed above. It mitigates market power by ensuring that rates are close to accounting costs.[221] It has been very successful in attracting capital to regulated industries. It is also perceived to provide incentives to cut costs. For example, between one rate case and another, the utility, which usually determines the timing and frequency of rate cases, keeps all cost savings but bears all costs incurred. Lags in adjusting rates, therefore, motivate the utility to control costs. Finally, under rate-of-return regulation, a denial of cost recovery for certain items may also be a powerful incentive.[222]

180. Although rate-of-return regulation offers a workable way of achieving the functions of a utility price system, it seems to have other undesirable effects.

- Rate-of-return regulation may promote inefficient production. For example, it may lead to the excessive use of capital, which increases average total costs.[223] Allocative efficiency is likely to be achieved through price setting that encourages the optimal quantity and quality of goods and services reaching customers who value them most.[224]

- Rate-of-return regulation may cause technical inefficiency or X-inefficiency.[225] Prices are unlikely to reflect marginal cost. Moreover, historical accounting costs, on which rates are based, may hardly be related to future replacement cost,[226] which promotes efficient pricing.

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[221] *See* Comments of the United States Department of Justice in Response to Notice of Proposed Policy Statement, April 27, 1992, at 7-8.

[222] *Supra* Note 182 at 4.

[223] *Supra* Note 220 at 562.

[224] *Supra* Note 221 at 6-7.

[225] *Supra* Note 220 at 562.

[226] *Supra* Note 221 at 7-8.

- Rate-of-return regulation may cause dynamic inefficiency manifested as restricting customer choice, forcing customers to accept excessive quality, and slowing a utility's dynamic productive efficiency.[227] Dynamic efficiency is likely to be achieved through encouraging process and product innovation.[228]

- Rate-of-return regulation has substantial administrative costs, which may be measured as the opportunity costs of implementing regulation and obtaining compliance.[229]

- Rate-of-return regulation has a tendency to encourage commodity throughput. If a utility has volumetric prices, then there is an incentive to increase sales and a disincentive both to decrease volume and to encourage prudent usage among customers.

- Rate-of-return regulation has a tendency to hinder the movement towards efficient tariff structures, which not only may expand the market and therefore attract new customers but also could encourage prudent usage among customers.

181. In response to the perceived limitations of rate-of-return regulation, alternative forms of "incentive" regulation, such as PBR, have been considered. The goal of these alternatives is to motivate a regulated monopolist utility to provide goods and services under terms and conditions that are similar to those in a competitive environment. There are several forms of IR, but most of them fall under one of two categories: price caps,[230] or PBR.

182. Under price caps, a ceiling is placed on rates or total revenues. A utility is free to charge prices that are below the cap, and to keep any cost savings.

- The growth of the cap is given by the expression CPI-X, or the difference between the consumer price index ("CPI") and an indicator of expected efficiency gains "X." The expected efficiency gain, X, can be based on historical efficiency gains in the industry or on other efficiency- or technology-related information that is independent of the utility.

- One variation of the expression CPI-X is CPI-X+Z, in which "Z" is a pass through item of cost over which the utility may have little control. For example, the fuel costs of an electric utility may be included in Z.[231]

[227] *Supra* Note 220 at 562-563.

[228] *Supra* Note 221 at 7.

[229] *Supra* Note 220 at 563.

[230] For a recommendation that "rate caps…be explicitly rejected, because the [sic] create an incentive for increased utility sales whenever short-run marginal costs are lower than rates," see Lazar, *Supra* Note 167 at 7.

[231] For a view that, if "fuel costs are not included in the price cap, utilities would have little or no incentive to adopt renewables," see Datta, *Supra* Note 15 at 22.

- The cap is typically adjusted periodically. The more often the cap is adjusted, the closer incentive regulation is to traditional cost-of-service regulation. The less often the cap is adjusted, the stronger is the incentive for the utility to reduce costs.

- Under a "revenue cap" or "decoupling mechanism," the utility's total revenue per customer ("RPC") is set to a defined level. If consumption declines, the utility is made whole, but if it increases, the incremental net revenue is rebated to customers. Under an RPC, utility revenue grows with new business but not with expanded sales to existing customers. RPC is reputedly "…the preferred form of regulation to encourage utility support for renewable resources and efficiency" among PBR mechanisms, but "…will not necessarily bias the utilities in favor of renewable resources or efficiency resources."[232]

183. Under PBR, a utility faces rewards or penalties for meeting or falling short of performance standards.

- One form of PBR is yardstick competition, in which a utility's rates are adjusted on the basis of an index derived from the actual costs of peer utilities.

- In another form of PBR, refunds to customers are granted according to utility performance. The PBR is designed in such a way that the poorer the performance, the greater the refunds. As a result, the utility has an incentive not to cut quality as it cuts costs.[233]

- Still another form of PBR is a sharing mechanism, in which the utility shares in the benefits or costs of meeting or missing a certain target. For example, the utility keeps 50% of fuel cost savings if it reduces fuel costs by more than its peers, but loses 50% of the savings if it does not reduce fuel costs by as much as its peers.[234]

- Yet another form of PBR is the provision of additional return or similar bonus return for meeting a standard, such as the achievement of the RPS, or investments in least-cost renewable energy resources or efficiency.[235]

184. An interesting form of IR is the creation of a market for trading permits or certificates that count toward the satisfaction of a certain standard. For example, electric power plants have participated in pollution markets for sulfur emission permits. The plant has a choice of buying permits at the going

[232] *Supra* Note 167 at 7 and 9.

[233] According to Colin M. Jones, *General Comments*, November 4, 2004, at 2, there is a need for a system that provides an incentive for the utility not only to reduce operating costs but also to maintain reliable power delivery.

[234] According to Datta, *Supra* Note 15 at 30, "positive shareholder incentives to share in the savings created from reduced fuel costs and risks to Hawaii's ratepayers would have the benefit of creating utility incentives to lower total consumer energy bills through renewable power and energy efficiency," and "this incentive is the single most important incentive to align utility management behavior to achieving the RPS."

[235] *See* Datta, *Supra* Note 15 at 29. According to Lazar, *Supra* Note 167 at 2, "more than two decades ago, the state of Washington dictated a higher equity return on energy efficiency investments than for general utility plant."

market rate or implementing pollution abatement systems. It therefore has an incentive to implement pollution abatement at a cost equal to or less than its expectation of the permit's market price. As a result, the plants that can abate in the cheapest way are encouraged to do so, and the overall sulfur emission standard is likely to be met at the lowest total cost across plants.

185. IR is perceived to provide very strong incentives to keep costs close to the efficient level.

- Under a price cap, the link between costs and allowed prices is weakened considerably. The utility is therefore motivated to control costs.

- An IR regime typically allows a portion of cost savings to flow back to the utility. The utility is therefore motivated to pursue technological development that could further increase savings and reduce costs in future.

- IR is considered to generate new services and minimize cross-subsidization. It may also reduce the administrative cost of regulation and compliance if exogenous cost adjustments chosen by the regulator provide a reasonable estimate of changes in the utility's costs.

- IR may assist in the movement towards efficient tariff structures. Retail prices typically have several inefficiencies, such as cross-subsidization among customer classes, perverse incentives encouraging excessive or untimely usage, and inadequate inducements for the marginal customer, among others. A price cap is usually applied to the weighted average of retail tariffs rather than to one particular tariff rate alone. The different component tariffs may be adjusted up or down in order to satisfy the cap. Following the adjustment, the efficiency of the tariff system as a whole may improve.[236]

186. However, IR improperly implemented can have undesirable effects.

- Utilities may have incentives to reduce quality or reliability to unacceptable levels as a method to cut costs. For example, utility First Energy reduced its tree-trimming budget to reduce costs. Lack of tree-trimming was a major factor in the blackout that affected the U.S. northeast in August 2003. Monitoring a service quality index ("SQI"), or some form of performance measurement, may minimize reliability and quality reductions.[237]

- If penalties for reducing quality are low or unclear, then the incentive for cost reduction is likely to result in reduced quality. Of course the converse is also true: if penalties are too high, then utilities are likely to provide too much quality, and to pass the cost on to customers.

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[236] For example, in order to satisfy the so-called "inverse elasticity rule," the tariff designer may specify that the higher the price elasticity of demand, the lower the price. One criticism is that low-income customers, who are likely to have limited choices or alternatives, may comprise the bulk of the purchasers of services with inelastic demand.

[237] According to Lazar, *Supra* Note 167 at 9, "a 10-measure SQI in place for Puget Sound Energy, with annual reporting to the Commission and to consmers [sic], and an annual penalty of up to ½% of gross revenue, is proving sufficient to induce improved performance by the utility."

- Under a price cap CPI-X, finding the appropriate level of X is difficult. The X factor needs to be low enough to encourage the pursuit of new technologies and new customers, but high enough to ensure that the utility does not persistently earn profits above competitive levels.

- Under a price cap CPI-X+Z, the application of Z has to account for the party that could most efficiently bear the risk. For example, a standard cost pass-through has a tendency to transfer the bulk of the risk to customers.[238]

- Under a sharing mechanism, there is a tendency to weaken the incentive to cut costs.[239]

- The more often caps are reset or performance standards adjusted, the closer incentive regulation approaches traditional rate-of-return regulation. It is possible that incentive regulation adds substantial regulatory costs without corresponding benefits.

- Under a cap and trade program, say, for pollution, the problem of local pollution may persist if both the cap and the emission permit market are national. A polluter can purchase permits from the national market and continue to pollute the local area.

187. In short, IR is unlikely to be a panacea. There is a concern in Kauai that "…it may be difficult to craft an appropriate regulatory PBR regime which will deliver real benefits to a small island."[240] In the event an alternative regulatory regime is to be implemented in Hawaii, it might make sense to analyze the costs, benefits, and risks related, for example, to availability and reliability of renewable energy, affordability, fuel efficiency, security, customer service, the protection of rights, environmental stewardship, and quality of life.[241]

188. The impact of alternative regulatory regimes on electric utility tariffs seems to be a major concern. There is a belief that in Hawaii "…any new regulatory regime should provide incentives to reduce electricity costs and to avoid negative consequences to Hawaii's economy and disposable personal income."[242] However, "…it is not a given that the renewable portfolio standards can be met while reducing power prices," and "…the more likely it is that utility prices will in fact increase."[243]

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[238] According to Datta, *Supra* Note 15 at 30, "one of the critical failures in traditional rate of return regulation is that the rate payer bears all the fuel price risk," and "utilities in Hawaii have no incentive to manage fuel costs, yet, given the high oil prices fuel costs now account for nearly 50% of total rates." According to Lazar, *Supra* Note 167 at 9, "a demonstrated risk of fuel cost disallowance would…" encourage utilities to use renewable energy resources, which do not have "fuel" cost risks.

[239] For a view that "positive shareholder incentives based on sharing the total system value created by renewables would create strong positive incentives for achieving the RPS in the most cost effective manner," see Datta, *Supra* Note 15 at 22.

[240] *See* Nakazawa, *Supra* Note 20 at 3.

[241] *Supra* Note 194 at 1.

[242] *See* Maurice H. Kaya, *Letter to Ms. Catherine P. Awakuni*, November 15, 2004, at 3.

[243] *See* Bonnet, *Supra* Note 215 at 2.

Appendix B: First Workshop Participants and Providers of Written Comments

First Workshop Participants
November 22 and 23, 2004
Hawaii Supreme Court Courtroom and Conference Room
417 South King Street, Honolulu, HI

No.	Courtesy Title	First Name	Last Name	Organization
1	Mr.	Bill	Short	AM-Pres Corporation
2	Ms.	Sarah	Blane	Building Industry Association of Hawaii
3	Mr.	Steve	Holmes	City and County of Honolulu
4	Mr.	Colin	Jones	City and County of Honolulu
5	Dr.	David	Rezachek	Consultant to Honolulu Seawater Air Conditioning, LLC
6	Ms.	Lani	Nakazawa	Corporation Counsel - County of Kauai
7	Mr.	Michael	Tresler	County of Kauai - Director of Finance
8	Mr.	Maurice	Kaya	Department of Business, Economic Development, & Tourism
9	Dr.	John	Tantlinger	Department of Business, Economic Development, & Tourism
10	Mr.	Laurence	Lau	Department of Health
11	Mr.	Raymond	Carr	Department of Research & Development, County of Hawaii
12	Mr.	John	Cole	Division of Consumer Advocacy
13	Ms.	Cheryl	Kikuta	Division of Consumer Advocacy
14	Mr.	Manny	Macatangay	Economists Incorporated
15	Mr.	Peter	Kikuta	Goodsill Anderson Quinn & Stifel, LLP
16	Mr.	Tom	Williams	Goodsill Anderson Quinn & Stifel, LLP
17	Mr.	Carl	Freedman	Haiku Design and Analysis
18	Mr.	Larry	Kafchinski	Hamakua Energy Partners, L.P.
19	Mr.	Dan	Giovanni	Hawaii Electric Light Company, Inc.
20	Mr.	Warren	Lee	Hawaii Electric Light Company, Inc.
21	Dr.	Sharon	Miyashiro	Hawaii Energy Policy Forum
22	Mr.	Murray	Towill	Hawaii Hotel Association
23	Mr.	Mitch	Ewan	Hawaii Natural Energy Institute
24	Dr.	Rick	Rocheleau	Hawaii Natural Energy Institute
25	Mr.	Milton	Staackmann	Hawaii Natural Energy Institute
26	Mr.	Warren	Bollmeier II	Hawaii Renewable Energy Association
27	Mr.	Rick	Reed	Hawaii Solar Energy Association, Inc.
28	Sen.	J. Kalani	English	Hawaii State Senate
29	Mr.	Robbie	Alm	Hawaiian Electric Company, Inc.
30	Mr.	William	Bonnet	Hawaiian Electric Company, Inc.
31	Ms.	Susan	Char	Hawaiian Electric Company, Inc.
32	Ms.	Darcy	Endo-Omoto	Hawaiian Electric Company, Inc.
33	Mr.	Gary	Hashiro	Hawaiian Electric Company, Inc.
34	Mr.	Alan	Hee	Hawaiian Electric Company, Inc.
35	Ms.	Shari	Ishikawa	Hawaiian Electric Company, Inc.
36	Mr.	Darren	Ishimura	Hawaiian Electric Company, Inc.
37	Mr.	Tom	Joaquin	Hawaiian Electric Company, Inc.
38	Ms.	Patsy	Nanbu	Hawaiian Electric Company, Inc.
39	Ms.	Gayle	Ohashi	Hawaiian Electric Company, Inc.
40	Mr.	Leon	Roose	Hawaiian Electric Company, Inc.

No.	Courtesy Title	First Name	Last Name	Organization
41	Mr.	Ross	Sakuda	Hawaiian Electric Company, Inc.
42	Ms.	Estrella	Seese	Hawaiian Electric Company, Inc.
43	Mr.	Scott	Seu	Hawaiian Electric Company, Inc.
44	Mr.	Tom	Simmons	Hawaiian Electric Company, Inc.
45	Mr.	Barry	Utsumi	Hawaiian Electric Company, Inc.
46	Mr.	David	Waller	Hawaiian Electric Company, Inc.
47	Mr.	Hans (Ruedi)	Tobler	Kalaeloa Partners, L.P.
48	Mr.	Joseph	McCawley	Kauai Island Utility Cooperative
49	Mr.	Mike	Yamane	Kauai Island Utility Cooperative
50	Mr.	Shah	Bento	Law Office of Shah Bento, LLLC (for Apollo Energy Corporation)
51	Ms.	Kat	Brady	Life of the Land
52	Mr.	Henry	Curtis	Life of the Land
53	Mr.	Kal	Kobayashi	Maui County Energy Office
54	Mr.	Ed	Reinhardt	Maui Electric Company, Ltd.
55	Mr.	Jim	Lazar	Microdesign Northwest
56	Mr.	Glenn	Sato	Office of Economic Development, County of Kauai
57	Mr.	Kent	Morihara	Oshima Chung Fong & Chung LLP
58	Mr.	John	Crouch	PowerLight Corp.
59	Ms.	Catherine	Awakuni	Public Utilities Commission
60	Mr.	Michael	Azama	Public Utilities Commission
61	Mr.	Daniel	Bilderback	Public Utilities Commission
62	Mr.	Carlito	Caliboso	Public Utilities Commission
63	Mr.	Steven	Iha	Public Utilities Commission
64	Ms.	Brooke	Kane	Public Utilities Commission
65	Ms.	Michelle	Kau	Public Utilities Commission
66	Ms.	Janet	Kawelo	Public Utilities Commission
67	Ms.	Lisa	Kikuta	Public Utilities Commission
68	Ms.	Lisa	Kim	Public Utilities Commission
69	Mr.	Wayne	Kimura	Public Utilities Commission
70	Ms.	Carolyn	Laborte	Public Utilities Commission
71	Mr.	Kris	Nakagawa	Public Utilities Commission
72	Ms.	June	Oswald	Public Utilities Commission
73	Ms.	Kara	Skinner	Public Utilities Commission
74	Mr.	Richard	VanDrunen	Public Utilities Commission
75	Mr.	E. Kyle	Datta	Rocky Mountain Institute
76	Ms.	Natalie	Min	Rocky Mountain Institute
77	Mr.	George	Aoki	The Gas Company
78	Ms.	Lynne	Ebisui	The Gas Company
79	Ms.	Gail	Gilman	The Gas Company
80	Mr.	Steve	Golden	The Gas Company
81	Mr.	Tom	Kobashigawa	The Gas Company
82	Ms.	Eileen	Yoshinaka	U. S. Department of Energy
83	Mr.	Scott	Bly	U.S. Army
84	Capt.	David	Fleisch	USPACOM

Source: Hawaii Public Utilities Commission

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Appendix C: Design of RPS Programs in Individual States

Table C1 States with RPS, RPS-style Policies, & RPS/SA Policies

Number	State	Initiative	Effective Year	Final Year	Indicator	Unit	Basis
1	Arizona	RPS	2001	2007	1.1	Percent	Retail energy sales
2	California	RPS	2002	2017	20.0	Percent	Retail energy sales
3	Colorado	RPS	2007	2015	10.0	Percent	Retail energy sales
4	Connecticut	RPS	2000	2010	10.0	Percent	Retail energy sales
5	Hawaii	RPS	2004	2020	20.0	Percent	Retail energy sales
6	Illinois	RPS-style	2001	2020	15.0	Percent	Total energy
7	Iowa	RPS/SA	1997	Indefinite	105.0	MW	Annual capacity from renewables
8	Maine	RPS	1999	2005	30.0	Percent	Retail energy sales
9	Maryland	RPS	2004	2019	7.5	Percent	Retail energy sales
10	Massachusetts	RPS	2002	2009	4.0	Percent	Retail energy sales
11	Minnesota	RPS/SA	2003	2010	1,125.0	MW	Wind capacity
		RPS/SA	2003	2002	125.0	MW	Biomass
		RPS-style	2003	2015	10.0	Percent	Retail energy sales
12	Montana	RPS	2005	2015	15.0	Percent	Retail energy sales
13	Nevada	RPS	2002	2013	15.0	Percent	Retail energy sales
14	New Jersey	RPS	2001	2012	6.5	Percent	Retail energy sales
15	New Mexico	RPS	2004	2011	10.0	Percent	Retail energy sales
16	New York	RPS	2006	2013	25.0	Percent	Retail energy sales
17	Pennsylvania	RPS	2005	2020	18.0	Percent	Retail energy sales
18	Rhode Island	RPS	2007	2019	16.0	Percent	Retail energy sales
19	Texas	RPS/SA	2002	2009	2,880.0	MW	Renewables capacity
20	Vermont	RPS-style	2005	2012	Observed	Percent	Energy growth
21	Washington DC	RPS	2005	2022	11.0	Percent	Electricity supply
22	Wisconsin	RPS/SA	1998	2000	50	MW	Renewables capacity
		RPS	1999	2011	2.2	Percent	Retail energy sales

Figure C1 States with Standards Based on Percent of Retail Energy Sales

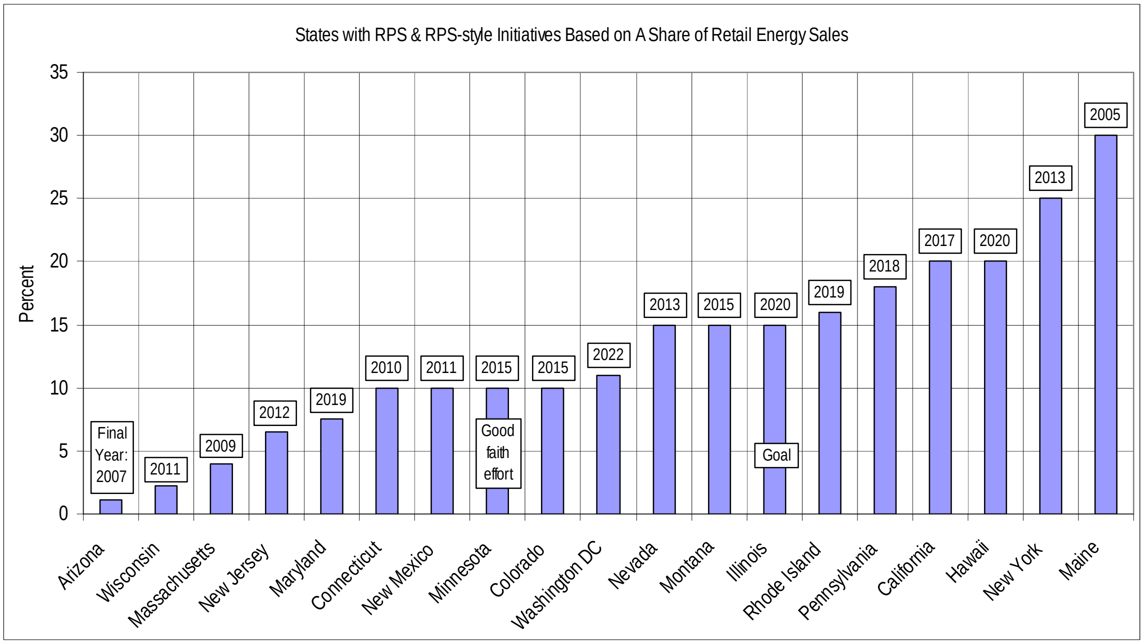

Figure C2 States with Standards Based on Capacity Level

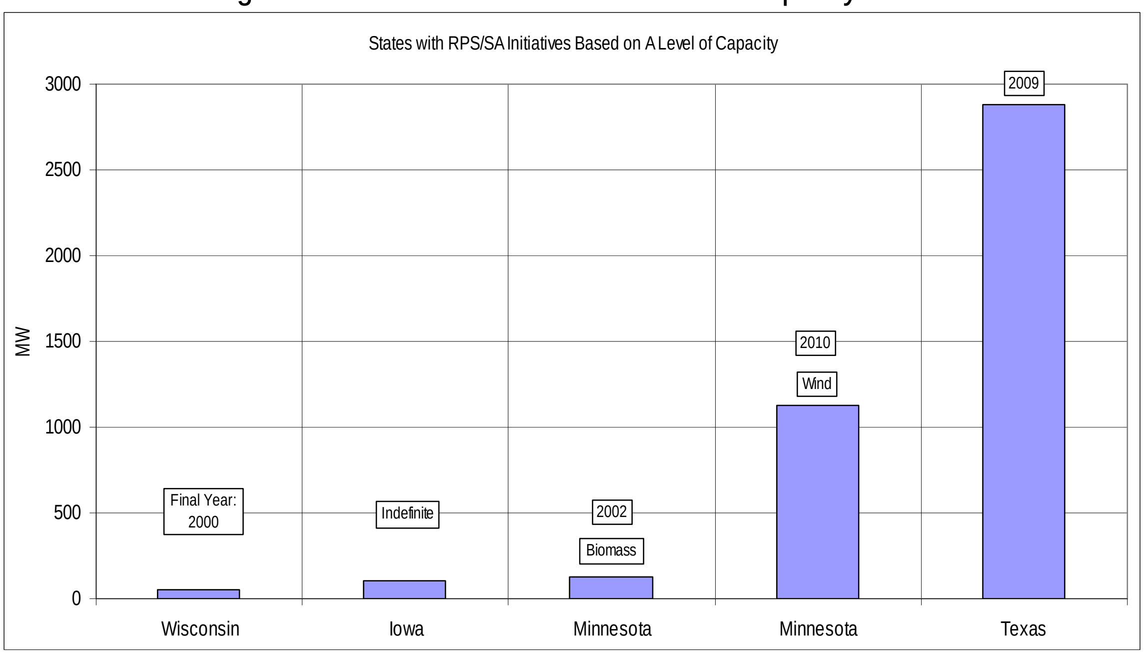

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Table C2 Regulation under RPS, RPS-style Policies, & RPS/SA

Number	State	Initiative	Credit Trading	Customer Charge	Compliance Fee	Rate Base	Penalties
1	Arizona	RPS	Yes	Yes	No	Unclear	No
2	California	RPS	No	Yes	No	Yes	Yes
3	Colorado	RPS	Yes	No	No	Yes	No
4	Connecticut	RPS	Yes	Yes	Yes	Yes	No
5	Hawaii	RPS	N/A	N/A	N/A	N/A	N/A
6	Illinois	RPS-style	No	N/A	N/A	N/A	N/A
7	Iowa	RPS/SA	No	No	No	Yes	No
8	Maine	RPS	Yes	No	No	Unclear	Yes
9	Maryland	RPS	Yes	No	Yes	Yes	No
10	Massachusetts	RPS	Yes	Yes	Yes	Yes	Yes
11	Minnesota	RPS/SA	No	N/A	N/A	N/A	N/A
		RPS/SA	No	N/A	N/A	N/A	N/A
		RPS-style	Yes	N/A	N/A	N/A	N/A
12	Montana	RPS	Yes	No	No	Yes	Yes
13	Nevada	RPS	Yes	No	No	Yes	Yes
14	New Jersey	RPS	Yes	No	No	Yes	Yes
15	New Mexico	RPS	Yes	No	No	Yes	Yes
16	New York	RPS	No	Yes	No	No	No
17	Pennsylvania	RPS	Yes	No	Yes	Unclear	No
18	Rhode Island	RPS	Yes	No	Yes	Yes	Yes
19	Texas	RPS/SA	Yes	No	No	Yes	Yes
20	Vermont	RPS-style	Yes	No	Yes	Unclear	No
21	Washington DC	RPS	Yes	No	Yes	Yes	No
22	Wisconsin	RPS/SA	No	No	No	Yes	No
		RPS	Yes	No	No	Yes	Yes

Appendix D: Candidate Renewable Resource Projects in Hawaii

Table D1 Capital Costs for Various Power Generating Technologies

Technology	2003 Capital Cost in 2002 $/kW
Gas/oil combined cycle	$542
Advanced gas/oil combined cycle	$615
Wind	$1,015
Coal	$1,168
Coal gasification cycle	$1,383
Landfill Gas	$1,477
Biomass	$1,731
Advanced nuclear	$1,928
Fuel cells	$2,162
Geothermal	$2,203
Solar thermal	$2,916
Solar photovoltaic	$4,401

Source: Energy Information Administration, *Assumptions to the Annual Energy Outlook 2004*, Table 38, at 71, available at http://www.eia.doe.gov/ last visited on January 13, 2005.

Table D2 Candidate Wind Projects

Island	Location	Source	Capacity MW	Capital Cost $/kW	Operating Cost $M	Cost of Energy ¢/kWh
Hawaii	Lalamilo Wells	(2) & (3)	3	1,237	0.05	4.4
		(2) & (3)	30	1,244	0.57	4.6
		(2) & (3)	50	1,191	0.95	4.4
	N. Kohala	(2) & (3)	5	1,280	0.11	4.3
		(2)	10	1,552	0.24	4.7
		(3)	15	N/A	N/A	4.3
	Kahua Ranch	(2) & (3)	10	1,418	0.18	5.2
Kauai	N. Hanapepe	(2) & (3)	10	1,351	0.16	6.1
	Port Allen	(2) & (3)	5	1,186	0.07	6.9
Maui	Kaheawa Pastures	(3)	10	1,241	0.20	5.1
		(2)	20	1,250	0.46	4.3
	NW Haleakala	(2) & (3)	10	N/A	0.21	5.2
		(2) & (3)	30	1,281	0.60	6.0
		(2) & (3)	50	1,213	1.01	5.7
	Puunene	(2) & (3)	10	1,219	0.16	6.1
		(2) & (3)	30	1,294	0.46	7.8
Oahu	Kaena Point	(2) & (3)	3	1,250	0.05	6.6
		(1) & (3)	15	1,279	0.24	6.6
	Kahe	(1)	25	1,851	0.86	N/A
		(1)	50	1,770	N/A	N/A
	Kahuku	(1)	10	2,343	0.72	N/A
		(1)	20	2,072	1.25	N/A
		(2)	30	N/A	N/A	6.7
		(2)	50	N/A	N/A	5.9
		(2)	80	N/A	N/A	6.9

(1) HIRP, (2) GEC, (3) WSB. Cost estimates are the lesser of figures reported in HIRP, GEC, and the nominal scenario of WSB.
Kahua Ranch is included only in future scenarios by GEC due to current transmission constraints.
N. Hanapepe is included only in future scenarios by GEC due to local opposition.
Kaheawa Pastures has 10 MW expansion option in future scenarios by GEC.

Table D3 Candidate Solar Projects

Island	Project	Location	Source	Capacity MW	Capital Cost $/kW	Operating Cost $M	Cost of Energy ¢/kWh
Hawaii	Fixed PV	N. Kohala	(2)	5.00	4,924	0.05	21.90
	Parabolic Trough	N. Kohala	(3)	30.00	N/A	N/A	7.70
		Keahole	(3)	30.00	N/A	N/A	7.70
		Waikoloa	(3)	30.00	N/A	N/A	7.70
Oahu	Fixed PV	Pearl Harbor	(2)	5.00	5,060	0.06	25.70
	Parabolic Trough	Pearl Harbor	(3)	30.00	N/A	N/A	7.70
		N. Ewa Plain	(3)	50.00	N/A	N/A	7.70
		Lualualei	(3)	50.00	N/A	N/A	7.70
Maui	Parabolic Trough	Kahului	(3)	30.00	N/A	N/A	7.70
		Kihei	(3)	30.00	N/A	N/A	7.70
		Puunene	(3)	30.00	N/A	N/A	7.70
Kauai	Parabolic Trough	Barking Sands	(3)	10.00	N/A	N/A	7.70
Unspecified	Fixed PV	PV Energy Park	(1)	0.10	8,800	8.20	N/A
Unspecified	Tracking PV	PV Energy Park	(1)	0.10	10,600	10.79	N/A

(1) HIRP, (2) GEC, (3) WSB. WSB assumes that parabolic trough systems are not implemented in the near term, from 2003 to 2008, and that they are only viable in the mid-term, from 2008 to 2018.

Table D4 Other Candidate Renewable Projects

Resource	Island	Location	Source	Capacity MW	Capital Cost $/kW	Operating Cost $M	Cost of Energy ¢/kWh
Biomass	Hawaii	East side of Island	(2)	10.0	3,264	0.04	5.1
	Oahu	Barber's Point	(1)	16.0	6,948	4.85	N/A
		Waialua	(1)	25.0	3,306	6.71	N/A
Geothermal	Hawaii	Kilauea	(2)	30.0	2,848	6.00	5.8
Hydroelectric	Hawaii	Umauma Stream	(2)	13.8	2,208	0.22	8.3
	Kauai	Wailua River	(2)	6.6	2,153	0.20	10.1

(1) HIRP, (2) GEC, (3) WSB. All candidate projects considered by GEC are included only in future scenarios due to current technology constraints.

Appendix E: The Issue of Avoided Cost Calculation

189. The Public Utilities Regulatory Policies Act ("PURPA") was one of five bills in the National Energy Act of 1978.[244] PURPA established Qualifying Facility ("QF") status for small producers using renewable energy sources, and cogenerators. QFs are exempt from regulation from the Public Utility Holding Company Act ("PUHCA") and the Federal Power Act ("FPA"). PURPA required the utility to buy whatever QF power was offered at avoided cost, or the incremental cost the utility would have incurred to produce or purchase energy from an alternative source.

190. The states were given the authority to determine avoided costs, and the method for determining avoided costs varies from one state to another. Some states were aggressive in determining the avoided cost that the utility has to pay QFs, and set prices relatively high. Many states required a utility to write long-term contracts with QFs of 10 to 20 years. The combination of high avoided costs and long-term contracts led to calls to amend or repeal parts of PURPA.[245] Utilities were locked with QFs in contract prices that were higher than actual avoided costs. To avoid these problems, many states have since reduced the length of contracts or implemented bidding systems for determining avoided costs.

191. PURPA led to strong growth in non-utility renewable energy sources. However, such growth slowed down in the 1990s as prices for fossil-fuel energy sources stabilized and were lower than forecasted.[246] By the late 1980s and early 1990s, oil prices had stabilized, natural gas prices had declined, and excess generating capacity in most regions of the country, especially the southwest and the northeast, allowed utilities to buy capacity and energy at much lower prices than had been forecast a decade earlier.[247] As a result, actual avoided costs became lower than the prices in long-term contracts that were written on the basis of expectations of sharply rising oil and natural gas prices.

192. In a series of cases since 1994, the Federal Energy Regulatory Commission ("FERC") has ruled that states cannot force utilities to pay higher renewable energy prices in the presence of cheaper alternatives.[248] Contracts signed prior to the FERC rulings were not affected, but subsequent contracts were affected, and growth in QFs slowed. Although FERC has maintained that states cannot set QF

[244] *See* Energy Information Administration, Renewable Energy Annual 1998 Issues and Trends, *Renewable Electricity Purchases: History and Recent Developments*, March 1999, DOE/EIA-0628(98).

[245] *See* Amy Abel, "Electricity Restructuring Background: The Public Utility Regulatory Policies Act of 1978 and the Energy Policy Act of 1992," *CRS Report 98-419*, May 4, 1998.

[246] *Supra* Note 244.

[247] *See* Michael J. Zucchet, Renewable Energy Annual 1995, *Renewable Resource Electricity in the Changing Regulatory Environment* available at http://www.eia.doe.gov/ last visited on February 3, 2005.

[248] *See* Connecticut Light and Power Company, *Order Granting Petition for Declaratory Order*, Docket No. EL93-55-000, 70 F.E.R.C. ¶ 61,012 (January 11, 1995); Southern California Edison Company, *Order on Petitions for Enforcement Action Pursuant to Section 210(h) of PURPA*, Docket No. EL95-16-000, 70 F.E.R.C. ¶ 61,215 (February 23, 1995); and San Diego Gas & Electric Company, *Order on Petitions for Enforcement Action Pursuant to Section 210(h) of PURPA*, Docket No. EL95-19-000, 70 F.E.R.C. ¶ 61,215 (February 23, 1995). See also Michael J. Zucchet, "Renewable Resource Electricity in the Changing Regulatory Environment," Energy Information Administration, Renewable Energy Annual 1995 at xxviii-xxix.

rates above avoided cost, it has ruled that states may offer tax incentives to encourage generation.[249] States, therefore, may provide additional incentives to QFs for renewable energy. A number of federal tax incentives currently support non-utility renewable energy resources.

[249] *Supra* Note 244.