Planned Computer Simulations Facilitating the Analysis of Proposals for Implementing the Renewable Portfolio Standards Provision in Hawaii

September 23, 2005

Prepared by

Economists Incorporated

Manny A. Macatangay
Stuart D. Gurrea
Schyler M. Thiessen
Stephen E. Siwek
John R. Morris

Prepared for

Hawaii Public Utilities Commission
465 South King Street, Room 103
Honolulu, HI 96813

Executive Summary

Objective and Scope of this Paper

The objective of this paper is to propose a plan for the conduct of computer simulations of electric power production in Hawaii. The planned simulations are intended to assist the Hawaii Public Utilities Commission ("Commission") in the analysis of proposals for implementing in Hawaii the renewable portfolio standards ("RPS") provision as established under Hawaii Revised Statutes §§ 269-91 to 269-95. This paper presents for comments an initial set of assumptions that may be used in the planned simulations, such as time frame, inputs, regulatory framework, candidate renewable energy resources in Hawaii, and others, and is part of an on-going collaborative process facilitating the communication of the Commission's work-in-progress and the solicitation of feedback from stakeholders.

A one-day technical workshop is scheduled for October 5, 2005 for stakeholders interested in the technical details of the planned simulations. At the technical workshop, this paper, together with stakeholders' comments on it, will serve as a starting point for collaborative discussions on (a) various assumptions that may be used in the planned simulations and (b) technical or methodological details of the planned simulations themselves. This collaboration is expected to produce a set of inputs or assumptions that could be considered in the conduct of the planned simulations.

Legislative Mandate

Under the RPS statutes, the RPS is the percentage of electrical energy sales from renewable energy, and the share of renewable energy in an electric utility's total energy sales has to reach 8% by 2005, 10% by 2010, 15% by 2015, and 20% by 2020. An electric utility company and its affiliates may combine their renewable energy portfolios in order to comply with the RPS provision. The 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 in order to comply with the RPS provision. The ratemaking structure allows for deviations from the RPS provision 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"), a form of incentive regulation ("IR") providing rewards or penalties upon meeting or falling short of performance standards. The Commission is required 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.

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 the process of developing electric utility ratemaking structures as established under the RPS statutes. 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. The Commission pursuant to its legislative mandate may use such formally adopted rules to implement the RPS provision.

The Planned Computer Simulations

The plan to conduct computer simulations of electric power production in Hawaii is one aspect of the assistance provided to the Commission in the course of analyzing proposals for implementing the RPS provision. The proposals are gathered from various sources, such as the comments expected on this paper, the companion paper to this paper and the comments expected on it, and the collaborative discussions during the workshops that the Commission is organizing to encourage public discussion of and feedback to its work-in-progress.

Initial preparations for the planned simulations are under way. Data have been received from Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Limited ("MECO"), which are collectively referred to as the HECO Companies; and from Kauai Island Utility Cooperative ("KIUC"). Assurances have been made that, if applicable, the proprietary format in which their data are submitted will be protected. The integrity of the data is under review, and preliminary simulations for the HECO Companies and KIUC have been performed.

<u>Software, Simulations, and System Assumptions</u>

The primary tool to conduct the planned simulations of the Hawaii power sector is Strategist®, commercially available software that facilitates a comprehensive and integrated analysis of power supply, load, investments, and rate design. Three sets of simulations are initially planned: Baseline, Status Quo, and Alternative Scenarios. Baseline Simulations seek to approximate the existing commercial relationships in the power sector of Hawaii for a particular base year. Status Quo Simulations seek to forecast the operations of the power sector of Hawaii over 30 years under the current cost-of-service regulation. Alternative Scenarios Simulations seek to forecast the operations of the power sector of Hawaii over 30 years under an alternative regulatory regime, such as IR, including PBR.

A separate series of planned simulations is to be performed for each of the islands of Hawaii. The islands of Hawaii are assumed to remain not interconnected over the study period. All starting values in the model are to be calculated using a base year. Additional system assumptions may be prepared or used in the course of the planned simulations.

<u>Specific Assumptions for Each Utility</u>

Data for HECO, HELCO, and the island of Maui have been submitted to the Commission in the Strategist® format, and therefore require only a robustness assessment (*i.e.,* sensitivity of simulation outcomes to changes in assumptions). By contrast, data for Molokai, Lanai, and KIUC have been submitted to the Commission in other formats, and in some cases rudimentary or foundational assumptions have to be made in order to make the data conform to the software's requirements. The assumptions for Molokai and Lanai are mostly based on those for HECO, HELCO, and Maui. The assumptions for KIUC are broadly based on those for HECO, HELCO, and Maui, and on reasonable approximations formulated from other sources.

The specific assumptions for HECO, HELCO, MECO, and KIUC pertain to the growth of load, electric power capacity and generation, the heat content of fuel and fuel burn limits, the level and growth of transactions, costs of fuel and O&M, and others. Found at the end of this paper, Appendices A to D have the specific assumptions summarized in tabular form for HECO, HELCO, MECO, and KIUC, respectively. The tables of assumptions in Appendices A to D are organized according to (a) the particular features of the island power systems they represent and (b) the scope of the data provided by the utilities to the

Commission. Additional specific assumptions may be prepared or used in the course of the planned simulations.

Representation of the Regulatory Framework

The Hawaii power sector is assumed to remain without any major restructuring over the study period. Cost-of-service regulation may be represented through the interaction among the Strategist® modules for load, production, and finance. The relevant measure of the RPS as established under the RPS provision is assumed to be the share in total electricity sales of both renewable energy generation and quantifiable energy conservation or conserved energy. In the determination of compliance to the RPS provision, energy savings, which under the RPS statutes are eligible renewable energy resources but which reduce total electricity sales, are not added back to total electricity sales. Energy conservation or conserved energy, which may be represented through conservation and demand-side management ("DSM") programs affecting load forecasts, could be estimated and counted as an eligible renewable energy resource in the determination of compliance to the RPS provision.

Compliance with the RPS provision is assumed to be in reference to the following milestone years, durations, and percentages: at least seven percent at any time between December 31, 2003 and December 30, 2005; at least eight percent at any time between December 31, 2005 and December 30, 2010; at least 10% at any time between December 31, 2010 and December 30, 2015; at least 15% at any time between December 31, 2015 and December 30, 2020; and at least 20% from December 31, 2020 onwards.

Under the RPS statutes, cost-effectiveness means the production or purchase of energy, firm capacity, or both from renewable energy resources at or below avoided costs. It follows that avoided cost may have to be estimated. There could be at least two approaches to avoided cost estimation: the first is through an inference from the proceedings of a current docket in the Commission on avoided cost calculation in Hawaii, and the second is through the current practices of HECO, HELCO, MECO, and KIUC. The role of avoided cost in the RPS statutes may be represented in the planned simulations through an iterative process aimed at identifying a generation mix that not only complies with the RPS provision but also includes only cost-effective renewable energy.

Representation of Prospective Renewable Energy Resources in Hawaii

Hawaii currently has a wide range of renewable energy resources, such as biomass, geothermal, hydro, wind, and solar. Candidate renewable projects identified in the following documents may be used as an initial set of possible renewable projects in the planned simulations: the 3rd cycle of HECO's Integrated Resource Plan, a study conducted by Global Energy Concepts for the Hawaii Department of Business, Economic Development, and Tourism, and a study conducted by WSB-Hawaii in support of the Hawaii Energy Policy Forum. Candidate renewable energy projects may also be selected from archetypical (*i.e.,* stylized example) renewable projects prepared for the planned simulations. The consideration of any candidate renewable energy project for possible use in the planned simulations does 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 current Integrated Resource Planning process in the Commission.

Hydro, pumped storage, and thermal units may be represented through a detailed characterization of their cost and operational profiles as provided in the model and software. DSM or conservation programs may be represented through their load reduction effect, which is included in the resource optimization. Biomass and geothermal resources may be represented as thermal units because their typical cost and operational profiles can be considered to be broadly similar to those of thermal units. Solar and wind resources may be represented as transactions, which are contracts for energy delivery at a certain quantity, price, location, and period of time, because their capacity is available only in certain hours.

Remote or off-grid technologies, such as commercial and residential PV and sea water air conditioning, may be represented as DSM or conservation programs, in view of their effect of reducing load approximately by the amount of energy available from them, and their inability, by their nature as off-grid resources, directly to serve load elsewhere on the grid.

If deemed necessary, a capacity credit, which is a payment that may be provided in recognition of a plant's contribution to system reliability, could be represented as a fixed payment offsetting a portion of the cost of renewable resources. Various financial instruments, if deemed necessary, may be represented as fixed payments offsetting a portion of the cost of renewable energy resources.

Table of Contents

I. Introduction

A. Legislative Mandate

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 provision 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.

2. The RPS statutes of Hawaii were originally enacted in 2001 as Act 272, and modified in 2004 as Act 95. Under the RPS statutes 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

---

[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
(5) Twenty per cent of its net electricity sales by December 31, 2020.

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

3. Under the RPS statutes 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 comply with the RPS provision in a cost-effective manner, and on a variety of other factors potentially affecting the implementation of RPS statutes, including those deemed appropriate by the Commission.[9] And the Commission is to report its findings on, and revisions to, the RPS statutes 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. 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 that could be adopted in a conventional rulemaking process. Such formally adopted rules to implement the RPS statutes may be used by the Commission pursuant to its legislative requirements. The assistance provided to the Commission broadly has the following elements:

   - Identify lessons from the components and IR mechanisms of other RPS programs;

   - Identify inputs consisting of candidate RPS components and IR mechanisms for potential implementation of RPS statutes in Hawaii;

   - Use the lessons learned and inputs identified, among others, in computer simulations of electric power production in Hawaii to determine and evaluate candidate electric utility ratemaking structures;

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).

- 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. The Planned Computer Simulations

5. One aspect of the assistance provided to the Commission is a plan to use computer simulations in the evaluation of RPS statutes implementation proposals gathered from various sources, such as the companion paper[11] to this technical paper, the comments on those papers, and the interactions during the three two-day collaborative workshops that the Commission is organizing to encourage public discussion of its work-in-progress.[12] The approach to, inputs to, and results of the planned simulations are subject to review on an on-going basis.

6. Initial preparations for the planned simulations are under way. Data have been received from Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Limited ("MECO"), which are collectively referred to as the HECO Companies; and from Kauai Island Utility Cooperative ("KIUC"). Assurances have been made that, if applicable, the proprietary format in which their data are submitted will be protected. The integrity of the data is under review, and preliminary simulations for the HECO Companies and KIUC have been performed.

C. Objectives and Scope of this Technical Paper

7. The objective of this paper is to propose a plan for the conduct of computer simulations of electric power production in Hawaii. This paper presents for comments an initial set of assumptions that may be used in the planned simulations, such as time frame, inputs, regulatory framework, candidate renewable energy resources in Hawaii, and others.

8. Part II of this technical paper describes the software, simulations, and assumptions applicable to the entire Hawaii power system, such as parameters related to load, generation, and reserve margins. Part III describes the assumptions that are specific to each utility (see Appendices A to D for specific assumptions in tabular form for HECO, HELCO, MECO, and KIUC, respectively). Part IV describes the representation of regulation and certain features of the RPS statutes of Hawaii. Part V describes the representation of candidate renewable energy resources in the planned simulations.

D. Scheduled Technical Workshop

9. A one-day technical workshop is scheduled for October 5, 2005 for stakeholders who are interested in the technical details of the planned simulations. At the technical workshop, this paper, together with stakeholders' comments on it, will serve as a starting point for collaborative discussions on (a) various

---

[11] *See* Economists Incorporated, *Proposals for Implementing Renewable Portfolio Standards in Hawaii*, July 25, 2005.

[12] *See* Hawaii Public Utilities Commission, *Electric Utility Rate Design in Hawaii: An Initial Concept Paper*, November 1, 2004. The Commission held the first workshop in November 22 and 23, 2004 and has scheduled a second workshop for October 2005.

assumptions that may be used in the planned simulations and (b) technical or methodological details of the planned simulations themselves. It is part of an on-going collaborative process facilitating the communication of the Commission's work-in-progress and the solicitation of feedback from stakeholders.

10. The goals of the technical workshop could be to describe and gather comments on scenarios, assumptions, and other aspects of the planned simulations, the representation of regulation and certain features of the RPS statutes of Hawaii, and the representation of candidate renewable energy resources in the modeling of the Hawaii power sector. This collaboration is expected to produce a set of inputs or assumptions that could be considered in the conduct of the planned simulations.

11. Both the companion paper to this technical paper and its associated two-day workshop scheduled for October 3 and 4, 2005 are intended to focus on concepts underlying alternative incentive mechanisms proposed to facilitate the implementation of RPS statutes in Hawaii. By contrast, this technical paper and its associated technical workshop scheduled for October 5, 2005 are intended to focus on the modeling assumptions and the technical or methodological details of the planned simulations.

E. Comments

12. Comments are welcome and may focus on the following paragraphs:

- Paragraph 25;
- Paragraph 89;
- Paragraph 101; and
- Paragraph 112.

II. Software, Simulations, and System Assumptions

A. Software

13. Strategist®, commercially available software that facilitates a comprehensive and integrated analysis of power supply, load, investments, and rate design, is to be used in the planned simulations of the Hawaii power sector. Strategist® has several modules that interact with each other and represent various aspects of electric utility operations and planning.[13] It is one of the leading software for performing power sector simulations, and is used nationwide not only in the electric utility industry but also in regulatory and legal proceedings.

14. Microsoft Excel® is to be used in order to facilitate the creation of specific routines, called macros, for performing various calculations, handling data, managing the planned simulations, or customizing constraints, conditions, or other modeling representations that may be developed. Excel® macros, which use the visual basic programming language, are routinely deployed in industry, including electric utilities, and in regulatory and legal proceedings.

B. Simulations

15. Three sets of simulations are to be performed: Baseline, Status Quo, and Alternative Scenarios.[14] Baseline Simulations seek to approximate the existing commercial relationships in the power sector of Hawaii for a particular base year. Status Quo Simulations seek to forecast the operations of the power sector of Hawaii over several future years under the current cost-of-service regulation. Alternative Scenarios Simulations seek to forecast the operations of the power sector of Hawaii over several future years under an alternative regulatory regime, such as IR, including PBR.

16. The expected output of Baseline Simulations is an approximation of the existing commercial relationships in the power sector of Hawaii for a particular base year. A Baseline Simulation is expected to provide a meaningful starting point for the analysis involving future time periods. Given that the base year serves as a starting point of projections, it is important that, in the selected base year, atypical circumstances have not been identified, or that any identified atypical circumstances are reasonably taken into account.

    - An acceptable Baseline Simulation is determined from the validity and stability of results after repeated runs. A simulation is valid if the results reasonably represent the current conditions of the power system, and is stable if the results do not change dramatically with small changes in assumptions.

---

[13] *Ibid*. The modules were also discussed during the first workshop in November 2004. For a view that "…in Hawaii…we do not think that a huge investment in hourly modeling is necessarily appropriate," see Jim Lazar, *Comments of Jim Lazar, Consulting Economist (Utility Rate Design Concept Paper)*, November 15, 2004, at 8.

[14] *Supra* Note 12.

- One of the key steps is to perform a test simulation that captures the essential elements of the power system in Hawaii. A test simulation seeks to examine the model and data, estimate production and load relationships, and produce results that generally conform to actual data.

- Another key step is to perform a calibration in order to make any necessary adjustments. Test simulation results are compared to actual data in order to determine the magnitude and scope of adjustments. Deviations from actual data are documented, and possibly used, together with expert opinion, as inputs to the calibration and in preparation for additional test simulations, if needed. A sensitivity analysis determines the bounds of the test simulation. Calibration ceases as soon as a reasonable stopping criterion, such as a comfortably small deviation from actual data, has been met, and an acceptable Baseline Simulation result has been identified and adopted.

17. The expected output of Status Quo Simulations is a forecast of electric utility rate designs over the study period under cost-of-service regulation. The diversity of Status Quo Simulations depends on the sub-cases that can reasonably be considered in planning the implementation of the RPS statutes through cost-of-service regulation. Uncertainty in Status Quo Simulations can be taken into account through the use of a reasonable range of inputs in order to assess the sensitivity and robustness of the forecasts.[15]

18. The expected output of Alternative Scenarios Simulations is a forecast of electric utility rate designs over the study period under IR. The diversity of the Alternative Scenarios Simulations depends on the variety of IR elements that can reasonably be considered in planning the implementation of the RPS statutes through IR.[16] Uncertainty in Alternative Scenarios Simulations can be taken into account through the use of a reasonable range of inputs in order to assess the sensitivity and robustness of the forecasts.

C. Geographic Scope, Base Year, and Study Period

19. A separate series of planned simulations is to be performed for each of the islands of Hawaii. The islands of Hawaii are currently not interconnected, and are assumed to remain not interconnected over the study period. This assumption is compatible with Hawaii's RPS provision allowing an electric utility company and its affiliates to combine their renewable energy portfolios in meeting the RPS.[17]

20. All starting values in the model are to be calculated using a base year. The base year generally includes actual data, and data for future years are typically taken from forecasts, escalations of actual data, or simulation results. A base year of 2004, the most recent complete calendar year, is to be used in the planned simulations. As indicated during the first workshop in November 2004, concerns have been raised over whether or not 2004 is a "normal" year that is suitable for use as a base year in view

[15] The issue of volatility was also discussed during the first workshop in November 2004.

[16] *Supra* Note 11.

[17] *Supra* Note 6.

of on-going rate cases or in-process capital projects.[18] The model and software, however, appear to be flexible enough to address these concerns.

- In the model and software, electric utility rates may be adjusted not only to reflect cost-of-service changes that are the subject of on-going rate cases, but also to account for any regulatory lag. As a result, the presence of on-going rate cases is unlikely to be a barrier to the selection of 2004 as a base year.
- In the model and software, net balances of on-going capital expenditures may be taken into account at the beginning of each simulation year. As a result, the presence of in-process capital projects is unlikely to be a barrier to the selection of 2004 as a base year.

21. A study period of 30 years is to be used in the planned simulations.

- The study period represents the total time frame of the analysis and accounts for the differences in operating characteristics and life cycles among various resources. For example, 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. The use of an excessively short time frame for the simulation 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.
- The use of a time frame spanning decades is common. For example, the Energy Information Administration, under the Office of Integrated Analysis and Forecasting of the U.S. Department of Energy, has produced a report, "Annual Energy Outlook 2005 With Projections to 2025," that has forecasts and analysis of U.S. energy supply, demand, and prices through 2025.[19]
- The final milestone year of the Hawaii RPS statutes is 2020.[20] In the planned simulations, RPS statutes compliance is assessed over the first 15 years, from 2006 to 2020, of the 30-year study period.

D. Other System Parameters

22. The Federal Income Tax Rate is assumed to remain unchanged at its current level of 35%.

23. The discount rate is assumed to be 8.42%, which is the discount rate used by the HECO Companies, according to their data submission to the Commission. In the absence of specific information on the

[18] *See e.g*. William A. Bonnet, *Comments Relating to the RPS Initial Concept Paper*, November 15, 2004, at 6.

[19] *See* Energy Information Administration, *Annual Energy Outlook 2005 With Projections to 2025*, February 2005 available at http://www.eia.doe.gov/oiaf/aeo/ last visited on August 4, 2005.

[20] *Supra* Note 5.

discount rate from KIUC, it seems reasonable to use, as a proxy, HECO Companies' information submitted to the Commission.

24. Additional system assumptions may be prepared or used in the course of the planned simulations.

E. Comments

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

- Software;
- Baseline simulation;
- Status Quo Simulation;
- Alternative Scenarios Simulation;
- Geographic scope;
- Base year;
- Study period;
- Federal Income Tax Rate; and
- Discount rate.

III. Specific Assumptions for Each Utility

26. Data for HECO, HELCO, and the island of Maui have been submitted to the Commission in the Strategist® format, and therefore require only a robustness assessment (*i.e.,* sensitivity of simulation outcomes to changes in assumptions). By contrast, data for Molokai, Lanai, and KIUC have been submitted to the Commission in other formats, and in some cases rudimentary or foundational assumptions have to be made in order to make the data conform to the software's requirements. The assumptions for Molokai and Lanai are mostly based on those for HECO, HELCO, and Maui. The assumptions for KIUC are broadly based on those for HECO, HELCO, and Maui, and on reasonable approximations formulated from other sources.

27. The specific assumptions for HECO, HELCO, MECO, and KIUC are to be subjected to robustness assessments. If, through a robustness assessment, a change in an assumption is determined to have an insignificant impact on simulation results, then that particular assumption can be kept fixed, and a reasonable range of values for other assumptions can be used in order to account for uncertainty.

28. The specific assumptions for HECO, HELCO, MECO, and KIUC are summarized in tabular form in Appendices A to D respectively. The tables of assumptions in Appendices A to D are organized according to (a) the particular features of the island power systems they represent and (b) the scope of the data provided by the utilities to the Commission. Additional specific assumptions may be prepared or used in the course of the planned simulations.

A. HECO

29. The specific assumptions for HECO are summarized in tabular form in Appendix A.

30. Annual load growth in HECO is assumed to be between 1% and 3.4%, as provided by HECO to the Commission. This range is broadly consistent not only with the average growth rates projected in the U.S. from 2003 to 2025 (*i.e*., 1.9% for total load, 1.6% for the residential sector, 2.5% for the commercial sector, and 1.3% for the industrial sector)[21] but also with the range of load growth assumptions used for HELCO (*i.e*., between 2.3% and 3.3%) and Maui (*i.e*., between 2.5% and 3.2%).

31. The seasonal load shape in HECO is assumed to be constant throughout the study period. In the absence of detailed information on current or future changes in seasonal loads in HECO, it seems reasonable to make this assumption.

32. For HECO, the minimum reserve margin is assumed to be 0%, and the maximum reserve margin, 50%, as provided by HECO to the Commission. The maximum reserve margin for HECO, however, can also be assumed to cover a range from 40% to 60% in increments of 10 percentage points. The level could be selected on the basis of its potential effect on electric utility rates. The assumed range of maximum reserve margins may reflect the varying intensity of regulatory pressure encouraging HECO to determine the optimal level and cost of system reliability.

[21] *Supra* Note 19 at 87.

33. HECO fuel cost assumptions are based on information provided by HECO to the Commission. The annual growth in diesel cost in HECO is assumed to be between 0% and 6.1%. The annual growth of coal cost in HECO is assumed to be between 1.8% and 3.5%. The cost of biomass in HECO is assumed to be constant. The annual growth in low-sulfur fuel oil ("LSFO") cost in HECO is assumed to between 0% and 9.3%.

34. Unit fixed costs and variable costs of thermal units in HECO are assumed to be constant, as provided by HECO to the Commission. The thermal units in HECO are assumed to have a fixed technology upon installation and to be well maintained throughout their useful lives.

B. HELCO

35. The specific assumptions for HELCO are summarized in tabular form in Appendix B.

36. Annual load growth in HELCO is assumed to be between 2.3% and 3.3%, as provided by HELCO to the Commission. This range is broadly consistent not only with the average growth rates projected in the U.S. from 2003 to 2025 (*i.e.*, 1.9% for total load, 1.6% for the residential sector, 2.5% for the commercial sector, and 1.3% for the industrial sector)[22] but also with the range of load growth assumptions used for HECO (*i.e.*, between 1% and 3.4%) and Maui (*i.e.*, between 2.5% and 3.2%).

37. The seasonal load shape in HELCO is assumed to be constant throughout the study period. In the absence of detailed information on current or future changes in seasonal loads in HELCO, it seems reasonable to make this assumption.

38. For HELCO, the minimum reserve margin is assumed to be 20%, and the maximum reserve margin, 100%, as provided by HELCO to the Commission. The maximum reserve margin for HECO, however, can also be assumed to cover a range from 40% to 60% in increments of 10 percentage points. The level could be selected on the basis of its potential effect on electric utility rates. The assumed range of maximum reserve margins may reflect the varying intensity of regulatory pressure encouraging HELCO to determine the optimal level and cost of system reliability.

39. Annual hydro energy generation and hydro energy seasonal distribution in HELCO are assumed to be constant, as provided by HELCO to the Commission. In the absence of specific information on changes in current or future annual hydro energy generation or hydro energy seasonal distribution in HELCO, it seems reasonable to make this assumption

40. From 2005 onwards, transaction energy (*i.e.*, contracts for energy delivery at a certain quantity, price, location, and period of time) existing before any power plant additions in HELCO is assumed to remain 2003 levels. In the absence of specific information on changes in current or future transaction energy for HELCO, it seems reasonable to make this assumption.

[22] *Supra* Note 19 at 87.

41. Seasonal distribution of transactions existing before any power plant additions in HELCO are assumed to be constant throughout the year. In the absence of specific information on changes in current or future seasonal distribution of transactions for HELCO, it seems reasonable to make this assumption.

42. HELCO fuel cost assumptions are based on information provided by HELCO to the Commission. The annual growth in diesel cost in HELCO is assumed to be between 1% and 5.9%. The annual growth in coal cost in HELCO is assumed to be between 0% and 3.7%. The cost in biomass in HELCO is assumed to be constant.

43. Fixed costs and variable costs of pumped storage in HELCO are assumed to be constant, as provided by HELCO to the Commission. Pumped storage in HELCO is assumed to have a fixed technology upon installation and to be well maintained throughout their useful lives.

44. Unit fixed costs and variable costs of thermal units in HELCO are assumed to be constant, as provided by HELCO to the Commission. The thermal units in HELCO are assumed to have a fixed technology upon installation and to be well maintained throughout their useful lives.

C. MECO

45. The specific assumptions for MECO covering the islands of Maui, Molokai, and Lanai are summarized in tabular form in Appendix C.

<u>Maui</u>

46. Annual load growth in Maui is assumed to be between 2.5% and 3.2%, as provided by MECO to the Commission. This range is broadly consistent not only with the average growth rates projected in the U.S. from 2003 to 2025 (*i.e*., 1.9% for total load, 1.6% for the residential sector, 2.5% for the commercial sector, and 1.3% for the industrial sector)[23] but also with the range of load growth assumptions used for HECO (*i.e*., between 1% and 3.4%) and HELCO (*i.e*., between 2.3% and 3.3%).

47. The seasonal load shape in Maui is assumed to be constant throughout the study period. In the absence of detailed information on current or future changes in seasonal loads in Maui, it seems reasonable to make this assumption.

48. For Maui, the minimum reserve margin is assumed to be 0%, and the maximum reserve margin, 100%, as provided by MECO to the Commission. The maximum reserve margin for Maui, however, can also be assumed to cover a range from 40% to 60% in increments of 10 percentage points. The level could be selected on the basis of its potential effect on electric utility rates. The assumed range of maximum reserve margins may reflect the varying intensity of regulatory pressure encouraging MECO to determine the optimal level and cost of system reliability in Maui.

49. From 2005 onwards, transaction energy (*i.e*., contracts for energy delivery at a certain quantity, price, location, and period of time) existing before any power plant additions in Maui is assumed to remain

[23] *Supra* Note 19 at 87.

2003 levels. In the absence of specific information on changes in current or future transaction energy for Maui, it seems reasonable to make this assumption.

50. Seasonal distribution of transactions existing before any power plant additions in Maui are assumed to be constant throughout the year. In the absence of specific information on changes in current or future seasonal distribution of transactions for Maui, it seems reasonable to make this assumption.

51. Maui fuel cost assumptions are based on information provided by MECO to the Commission. The annual growth in diesel cost in Maui is assumed to be between 0% and 5.9%. The annual growth in medium-sulfur fuel oil ("MSFO") cost in Maui is assumed to be between 2.7% and 4.1%. The cost of biomass in Maui is assumed to be constant.

52. Unit fixed costs and variable costs of thermal units in Maui are assumed to be constant, as provided by MECO to the Commission. The thermal units in Maui are assumed to have a fixed technology upon installation and to be well maintained throughout their useful lives.

Molokai

53. Annual load growth in Molokai is assumed to be between 1% and 2.3% from 2006 to 2020, as provided by MECO to the Commission, and by a weighted average of the load growth rates for HECO, HELCO, and Maui thereafter. This range is broadly consistent with the average growth rates projected in the U.S. from 2003 to 2025 (*i.e.*, 1.9% for total load, 1.6% for the residential sector, 2.5% for the commercial sector, and 1.3% for the industrial sector).[24]

54. The seasonal load shape in Molokai is assumed to be a weighted average of that in HECO, HELCO, and Maui. In the absence of detailed information on current or future changes in seasonal loads in Molokai, it seems reasonable to make this assumption.

55. For Molokai, the minimum and maximum reserve margins are assumed to be a weighted average of those for HECO, HELCO, and Maui. The maximum reserve margin for Molokai, however, can also be assumed to cover a range from 40% to 60% in increments of 10 percentage points. The level could be selected on the basis of its potential effect on electric utility rates. The assumed range of maximum reserve margins may reflect the varying intensity of regulatory pressure encouraging MECO to determine the optimal level and cost of system reliability in Molokai.

56. The annual fuel heat content in Molokai is assumed to be a weighted average of that in HECO, HELCO, and Maui. In the absence of detailed information on current or future changes in annual fuel heat content in Molokai, it seems reasonable to make this assumption.

57. Fuel heat content in Molokai is assumed to be a weighted average of that in HECO, HELCO, and Maui. In the absence of detailed information on current or future changes in fuel heat content in Molokai, it seems reasonable to make this assumption.

[24] *Supra* Note 19 at 87.

58. The annual growth in oil cost in Molokai is assumed to be between 0% and 5.9% from 2006 to 2020, as provided by MECO to the Commission, and to be a weighted average of that for HECO, HELCO, and the diesel cost in Maui thereafter.

59. Unit fixed costs and variable costs of thermal units in Molokai are assumed to be a weighted average of those for HECO, HELCO, and Maui. In the absence of detailed information on current or future changes in unit fixed costs or variable costs of thermal units in Molokai, it seems reasonable to make this assumption.

Lanai

60. Annual load growth in Lanai is assumed to be between 1% and 2% from 2006 to 2020, as provided by MECO to the Commission, and to be a weighted average of the load growth rates for HECO, HELCO, and Maui thereafter. This range is broadly consistent with the average growth rates projected in the U.S. from 2003 to 2025 (*i.e.*, 1.9% for total load, 1.6% for the residential sector, 2.5% for the commercial sector, and 1.3% for the industrial sector).[25].

61. The seasonal load shape in Lanai is assumed to be a weighted average of that in HECO, HELCO, and Maui. In the absence of detailed information on current or future changes in seasonal loads in Lanai, it seems reasonable to make this assumption.

62. For Lanai, the minimum and maximum reserve margins are assumed to be a weighted average of those for HECO, HELCO, and Maui. The maximum reserve margin for Lanai, however, can also be assumed to cover a range from 40% to 60% in increments of 10 percentage points. The level could be selected on the basis of its potential effect on electric utility rates. The assumed range of maximum reserve margins may reflect the varying intensity of regulatory pressure encouraging MECO to determine the optimal level and cost of system reliability in Lanai.

63. The annual fuel heat content in Lanai is assumed to be a weighted average of that in HECO, HELCO, and Maui. In the absence of detailed information on current or future changes in annual fuel heat content in Lanai, it seems reasonable to make this assumption.

64. Fuel heat content in Lanai is assumed to be a weighted average of that in HECO, HELCO, and Maui. In the absence of detailed information on current or future changes in fuel heat content in Lanai, it seems reasonable to make this assumption.

65. The annual growth in oil cost in Lanai is assumed to be between 0% and 6% from 2006 to 2020, as provided by MECO to the Commission, and to be a weighted average of that for HECO, HELCO, and the diesel cost in Maui thereafter.

66. Unit fixed costs and variable costs of thermal units in Lanai are assumed to be a weighted average of that in HECO, HELCO, and Maui. In the absence of detailed information on current or future changes

[25] *Supra* Note 19 at 87.

in unit fixed costs or variable costs of thermal units in Lanai, it seems reasonable to make this assumption.

D. KIUC

67. The specific assumptions for KIUC are summarized in tabular form in Appendix D.

Load

68. Annual load growth in KIUC is assumed to be between 1% and 2.5%. This range is broadly consistent not only with the average growth rates projected in the U.S. from 2003 to 2025 (*i.e.*, 1.9% for total load, 1.6% for the residential sector, 2.5% for the commercial sector, and 1.3% for the industrial sector)[26] but also with the range, from about 1% to 3.4%, of load growth assumptions used for HECO, HELCO, and Maui.

69. The seasonal load shape in KIUC is assumed to be constant throughout the study period. In the absence of detailed information on current or future changes in seasonal loads in KIUC, it seems reasonable to make this assumption.

70. Historical peak demand in MW of KIUC load groups is assumed to be in proportion to their 2004 energy sales in MWh. In the absence of further information on peak demand for each load group in KIUC, it seems reasonable to make this assumption.

Capacity and Generation

71. Wind plants in KIUC are assumed to provide 0.0% spinning contribution. In the absence of specific information on future wind or other conditions affecting the capability of a wind plant to run at a zero load and be synchronized to the electric power system in KIUC, it seems reasonable to make this assumption. Moreover, according to KIUC data submitted to the Commission, existing hydro plants and transactions in KIUC have 0.0% spinning contributions.

72. The minimum capacity for a future non-renewable LM2500 plant in KIUC is assumed to be 10% of maximum capacity. According to KIUC data submitted to the Commission, the operating characteristics of the existing KPS combustion turbine plant are similar to those of the LM2500 plant. The minimum capacity of a future coal plant in KIUC is assumed to be the average ratio of maximum to minimum capacity of similar future coal plants of HECO Companies. In the absence of specific information on minimum capacity of a future coal plant in KIUC, it seems reasonable to use, as a proxy, HECO Companies' information submitted to the Commission.

73. The future coal plant in KIUC is assumed to have the same maintenance rate and mature forced outage rate as similarly sized future coal plants of HECO Companies. In the absence of specific information on maintenance rates and mature forced outage rates, for similarly sized future coal plants

[26] *Supra* Note 19 at 87.

in KIUC it seems reasonable to use, as a proxy, HECO Companies' information submitted to the Commission.

74. The time-until-retirement of future non-renewable alternatives in KIUC is assumed to be 30 years. According to KIUC data submitted to the Commission, the KPS combustion turbine, which can run on diesel and naphtha but almost exclusively runs on naphtha, has a time-until-retirement of about 30 years. Moreover, a replacement plant considered for possible installation between 2007 and 2009 is thought by KIUC to have very similar operating data to KPS.

75. The minimum reserve margin for KIUC is 27.3%, as provided by KIUC to the Commission. The maximum reserve margin for KIUC, however, is assumed to range from 40% to 60% in increments of 10 percentage points. The level could be selected on the basis of its potential effect on electric utility rates. The assumed range of reserve margins may reflect the varying intensity of regulatory pressure encouraging KIUC to determine the optimal level and cost of system reliability.

76. Annual hydro energy generation from upper and lower hydro units in KIUC is assumed to be in proportion to their generating capacity. In the absence of specific information on generation from upper and lower hydro units in KIUC, it seems reasonable to make this assumption. If data are available, then annual hydro energy generation from upper and lower hydro units in KIUC could be assumed to be an average of their historical annual hydro energy generation.

77. The seasonal distribution of hydro energy generation for both existing and future hydro plants in KIUC is assumed to be the same.

78. In KIUC, seasonal hydro energy ratios, which express the share of total annual hydro energy generated in a month, are assumed to follow the monthly pattern of 2004 seasonal hydro energy output.

Fuel Heat Content and Burn Limits

79. The annual fuel heat content in KIUC is assumed to be a weighted average of monthly fuel heat content, with the number of days in a month as weights.

80. Heat content for future coal plants KIUC is assumed to be the average of those for similarly sized future coal plants in HECO Companies. In the absence of specific information on heat content in KIUC, for similarly sized future coal plants in KIUC it seems reasonable to use HECO Companies' information submitted to the Commission as a proxy.

81. In KIUC, the S1 plant, which runs on diesel, is assumed to have no minimum or maximum fuel burn limits. In the absence of specific information on minimum or maximum fuel burn limits in KIUC, it seems reasonable to minimize the constraints applied to the operation of a plant.

Transactions

82. From 2005 onwards, transaction energy (*i.e.,* contracts for energy delivery at a certain quantity, price, location, and period of time) existing before any power plant additions in KIUC is assumed to remain at 2003 levels. KIUC data submitted to the Commission have information on transactions in both 2003

and 2004. However, the increase in hydroelectric power production, from 30,100 MWh in 2003 to 36,500 MWh in 2004, and in power sales, from 21,200 MWh in 2003 to 30,500 MWh in 2004, of Kauai Coffee, one of the largest providers of transaction energy to KIUC, "… was due primarily to heavy rainfall in 2004."[27]

83. Seasonal transaction capacities existing before any power plant additions in KIUC are assumed to be constant throughout the year. In the absence of specific information on seasonal transaction capacities throughout the year for KIUC, it seems reasonable to make this assumption.

<u>Fuel and O&M Costs</u>

84. For the base year, the annual fuel cost in KIUC is assumed to be a weighted average of monthly fuel costs, with the number of days in a month as weights.

85. Coal costs for future KIUC coal plants are assumed to be the average of those for similarly sized future coal plants in HECO Companies. In the absence of specific information on coal costs in KIUC, for similarly sized future coal plants in KIUC it seems reasonable to use, as a proxy, HECO Companies' information submitted to the Commission.

86. First year O&M costs for alternative renewable energy resources in KIUC are assumed to apply throughout all operating years. In the absence of specific information on O&M costs for alternative renewable energy resources throughout all operating years in KIUC, it seems reasonable to make this assumption.

87. First year O&M costs in KIUC are assumed to begin with the in-service year and to apply throughout book life. In the absence of specific information on O&M costs during the in-service year and throughout book life in KIUC, it seems reasonable to make this assumption.

88. Unit fixed costs and variable costs of thermal units in KIUC are assumed to be constant, as provided by KIUC to the Commission. The thermal units in KIUC are assumed to have a fixed technology upon installation and to be well maintained throughout their useful lives.

E. Comments

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

- Specific assumptions on load;
- Specific assumptions on capacity and generation;
- Specific assumptions on fuel heat content and burn limits;

[27] *See* Alexander & Baldwin Inc., *Form 10-K*, March 8, 2005 (Period: December 31, 2004) at Items 1 and 2, Section E, in or around page 15.

- Specific assumptions on transactions; and
- Specific assumptions on fuel and O&M cost.

IV. Regulation and the Hawaii RPS Provision

A. Electricity Industry Restructuring

90. In Decision and Order No. 20584 filed on October 21, 2003, the Commission had noted the lack of consensus on options or recommendations for electricity industry restructuring in Hawaii,[28] and had elected "… to monitor restructuring activities in other states and at the federal level before proceeding with any major restructuring in Hawaii."[29]

91. The Hawaii power sector is assumed to remain without "any major restructuring" over the study period.

B. Cost-of-service Regulation

92. The three steps in modeling utility rates under cost-of-service regulation are functionalization, classification, and allocation, all of which are performed in order to assign costs to various rate classes.

- The first step, functionalization, assumes that various plant and equipment categories incur costs differently and are used differently by various customer classes. Functionalization, therefore, assigns cost items to categories, such as production, transmission, and distribution. For example, an industrial customer may use only production and transmission facilities, but a residential customer may use production, transmission, and distribution. Or some production costs may be directly related to the coincident peak of the rate class, but some distribution costs may be directly related to the non-coincident peak of the rate class.

- The second step, classification, apportions a percentage of costs and plant items among Customer, Demand, and Energy categories. Classification is done for each functionalized plant and expense item.

- The third step, allocation, assigns functionalized, classified costs and plant items to jurisdictions and rate classes. The basis for the allocation may be different for each cost item, but there is usually one allocation method for energy and customer allocations, such as the actual energy requirements and number of customers for each rate class, and a limited number of allocation methods for demand costs. The allocation methods are based on actual demand and energy usage and the number of customers for each rate class. The allocation step creates a matrix of functionalized items, classification categories, and rate classes. The matrix is aggregated to yield plant and cost items by rate class.

93. In the planned simulations, cost-of-service regulation, which requires, among others, the modeling of load, generation, utility operations and financial statements, and electric utility rate design, may be represented through the algorithms found in the production and financial modules of Strategist®.

---

[28] *See* Public Utilities Commission of the State of Hawaii, *In the Matter of Public Utilities Commission Instituting a Proceeding on Electric Competition, Including an Investigation of the Electric Utility Infrastructure in the State of Hawaii (Docket No. 96-0493)*, Decision and Order No. 20584 (October 21, 2003), at 8 and 9.

[29] *Ibid* at 9.

94. The three production modules in Strategist® are the Load Forecast Adjustment ("LFA") module, Generation and Fuel ("GAF") module, and Proview.

- In the planned simulations, the LFA may be used to represent the development and modification of load forecasts through an assessment of marketing, conservation, and demand-side management ("DSM") programs influencing consumption patterns.

- In the planned simulations, the GAF may be used to represent the operation of the utility and its participation in energy transactions through an optimal resource dispatch involving the interaction of fuel prices and usage, production costs, and emissions information, among others. The GAF may be used to determine the effects of changes in operating characteristics or market conditions.[30]

- In the planned simulations, Proview may be used to represent long-range expansion plans through a determination of the optimal scale, location, timing, and technology of capacity additions, subject to financial constraints.[31] The effects of additional generation or transmission capacity and load modification may also be determined over the simulation period.[32]

95. In Strategist®, the three financial modules that are central to the purpose at hand are the Capital Expenditure and Recovery ("CER") module, Financial Reporting and Analysis ("FIR") module, and the Class Revenue Module ("CRM"). In the planned simulations, the CER may be used to represent the utility's capability for capital attraction and investment through a financial analysis and a comparison of generation alternatives.[33] In the planned simulations, the FIR may be used to represent alternative construction programs, fuel cost scenarios, regulatory action, and financial market conditions through the creation and analysis of pro-forma financial statements. In the planned simulations, the CRM, which is part of the FIR, may be used to represent the process of designing rate structures for each customer class through the allocation of rate base and expense items to each rate class.

- The CRM combines the functionalization and classification steps in cost-of-service regulation. Plant and expense items are assigned to classification categories, such as Demand, Energy, or Customer. Functionalization is accomplished by defining asset classes and component schedules in the FIR. For example, production, transmission, distribution, and general plant categories may

---

[30] Information from GAF runs may be used to calculate loss of load probability or loss of load hours.

[31] For a view that an improvement in return without an increase in volatility through a mix of risky and riskless assets "…has significant implications for generating portfolios, where the inclusion of riskless renewables similarly can reduce risk and/or cost," 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 40.

[32] According to Datta, *Ibid* at 23-24, the issue of transmission "…will be especially important in the far flung systems of neighbor islands, where transmission constraints do preclude economic dispatch."

[33] For a view that "…each utilities' capital structure is a corporate business decision" and that "…the existing capital structure should be used," see Datta, *Ibid* at 24.

be segregated. Once the classification process is complete, the classified costs are allocated to the various jurisdictions and to rate classes within each jurisdiction.

- Plant and cost items are assigned to each rate class, and rates in each rate class may be designed to recover costs and provide an opportunity for the utility to earn a reasonable rate of return.[34] The rate case process may be represented through a repetition of the cycle, for example, every five years. The repetition cycle may be adjusted according to the experience of electric utility rate cases in Hawaii or some reasonable approximation.

C. Compliance with the RPS Provision

96. If the RPS regime ultimately implemented is rigid,[35] then the relevant measure under the RPS statutes of Hawaii is assumed to be the share in total electricity sales of renewable energy generation and quantifiable energy conservation or conserved energy.

- In the measurement of the RPS, energy savings, which are eligible renewable energy resources by law[36] but which reduce total electricity sales, are not added back to total electricity sales.[37]

- Energy conservation or conserved energy may be represented through the Strategist® module LFA that accounts for conservation and DSM programs in the development and modification of load forecasts. The conserved energy could be estimated and counted as an eligible renewable energy resource in the measurement of the RPS.

97. Compliance with the RPS provision is assumed to be in reference to the following milestone years, durations, and percentages:

- At least seven percent at any time between December 31, 2003 and December 30, 2005;

- At least eight percent at any time between December 31, 2005 and December 30, 2010;

- At least 10% at any time between December 31, 2010 and December 30, 2015;

- At least 15% at any time between December 31, 2015 and December 30, 2020; and

---

[34] For a view that the financial models should be able to evaluate asset equity, which is the financial measure of an electric cooperative, see Joseph McCawley, *KIUC Comments on PUC workshop concept paper*, November 15, 2004, at 1.

[35] *Supra* Note 11. Depending on the IR mechanisms ultimately adopted in Hawaii, the RPS regime may be flexible or rigid. Flexible regimes do not require a strict correspondence between the physical generation of renewable energy in Hawaii 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.

[36] *Supra* Note 4.

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

- At least 20% from December 31, 2020 onwards.

98. If the RPS regime ultimately implemented is rigid, the determination of compliance with the RPS provision may be represented through a constraint governed by a feedback mechanism between Strategist® and Excel®. Strategist® can be configured to send simulation results to Excel® in which an assessment could be performed to determine whether or not RPS compliance is achieved. If compliance with the RPS provision is achieved, then the feedback mechanism stops. If, however, compliance is not achieved, then, depending on the regulatory approach adopted in Hawaii, a parameter affecting utility behavior is adjusted and fed back to Strategist® as a starting input for the next simulation run, and the iteration continues until compliance is achieved or a relevant stopping criterion is met.

D. Avoided Cost

99. Under the RPS statutes, cost-effectiveness "…means the ability to produce or purchase electric energy or firm capacity, or both, from renewable energy resources at or below avoided costs."[38] Avoided cost may be estimated in at least two ways. First, an approach to avoided cost calculation could be developed from the proceedings of an on-going docket in the Commission, Docket No. 7310, on the calculation of avoided cost in Hawaii.[39] Second, an approach to avoided cost calculation may be initially determined from the current practices of HECO, HELCO, MECO, and KIUC.[40]

- The current practice of avoided cost calculation measures only short-run avoided costs, and includes changes in fuel costs, relatively minor "O&M adjustments," and, in the case of Schedule Q rates presumably intended for those taking power below 100 KW, a "Power Factor" adjustment.[41]

- Under the current practice, the Avoided Energy Cost and Schedule Q rates are both separated into peak and off-peak rates.[42] Peak and off-peak energy cost rates are a function of fuel price and heat rate. Fuel price is a composite fuel price reported in cents per BTU, and does not differ across peak and off-peak periods. Heat rate reported in BTU/KWh differs significantly across peak and off-peak periods and among various utilities.

---

[38] *Supra* Note 2.

[39] *Supra* Note 11. According to the Commission, updates by parties to Docket No. 7310 are due on or before September 30, 2005.

[40] *See* Hawaiian Electric Company, Inc., *Avoided Energy Cost Data and 3rd Quarter 2005 Schedule "Q" Rates*, June 30, 3005; Hawaii Electric Light Company, Inc., *Avoided Energy Cost Data and 3rd Quarter 2005 Schedule "Q" Rates*, June 30, 3005; Maui Electric Company, Limited, *Avoided Energy Cost Data and 3rd Quarter 2005 Schedule "Q" Rates*, June 30, 3005; and Kauai Island Utility Cooperative, *Fuel and Purchased Power Rate Adjustment*, June 30, 2005.

[41] *Ibid*.

[42] *Ibid*.

100. Avoided cost in the Hawaii RPS statutes may be incorporated in the planned simulations through a series of steps.

- An avoided cost benchmark for 30 years is obtained from either the utilities or the outcomes of Docket No. 7310, and then compared to renewable energy costs resulting from 30-year Status Quo and Alternative Scenarios Simulations.

- If the avoided cost benchmark is equal to or exceeds renewable energy costs, then the provision related to avoided cost in the RPS statutes is satisfied. If, however, the avoided cost benchmark is less than renewable energy costs, then the most expensive candidate renewable energy resources are excluded, and 30-year Status Quo and Alternative Scenarios Simulations are once again performed.

- The iteration continues until the avoided cost benchmark is equal to or exceeds renewable energy costs, or until a relevant stopping criterion is met. The constrained optimization, by construction, produces a generation mix that not only complies with the RPS provision but also includes only cost-effective renewable energy.

E. Comments

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

- Assumption on electricity industry restructuring in Hawaii;

- Representation of rate of return regulation;

- Representation of compliance with the RPS provision; and

- Representation of avoided cost.

V. Renewable Energy Resources in Hawaii

A. Hawaii

102. Hawaii currently has a wide range of renewable energy resources, such as biomass, geothermal, hydro, wind, and solar, among others.[43] Various renewable energy resources are not only available in Hawaii but also eligible for satisfying the RPS provision. As a consequence, a wide range of renewable energy resources in Hawaii may be considered and included in the planned simulations.

B. Selecting Renewable Energy Resources

103. The candidate renewable projects identified in the 3rd cycle of the Integrated Resource Plan of HECO, a study conducted by Global Energy Concepts for the Hawaii Department of Business, Economic Development, and Tourism, and a study conducted by WSB-Hawaii in support of the Hawaii Energy Policy Forum may be used as a starting point in the planned simulations.[44]

104. Candidate renewable energy projects may also be selected from archetypical (*i.e.,* stylized example) renewable projects prepared for the planned simulations. Archetypical renewable projects could include a wide range of technologies and remote or off-grid resources, such as commercial and residential Photovoltaics ("PV"). Archetypical renewable projects may be prepared from other studies, third parties, or combinations thereof.[45]

105. There may be differences in cost and performance estimates of specific renewable resources.[46] Revisions of renewable project estimates, estimates found in other reports, assessments performed by the Commission, or combinations thereof, may be selected for inclusion in the planned simulations. Selections may be made on an on-going basis in the course of the planned simulations. Selections or simulation results 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 Integrated Resource Planning process on-going in the Commission.

C. Representation of Candidate Renewable Resources

106. Hydro, pumped storage, and thermal units may be represented through a detailed characterization of their cost and operational profiles as provided in the model and software. DSM or conservation

---

[43] For a view that "…the alternatives for renewable energy in Hawaii are legion," see Lazar, *Supra* Note 13 at 4.

[44] *Supra* Note 11. See also Datta, *Supra* Note 31 at 26-27 for a list of other renewable resource technologies that may be considered.

[45] According to Bonnet, *Supra* Note 18 at 2, other factors, such as land use policy, permitting, and community concerns, may affect the achievement of the RPS. In the planned simulations, any potential delay in the development of alternative renewable resource projects may be represented through the use of a range of project start dates.

[46] For a view that "...inputs to any model regarding cost and availability of renewable resources are critical to any assessment..." of the RPS, see Bonnet, *Supra* Note 18 at 2.

programs may be represented through their load reduction effect, which is included in the resource optimization.

107. Biomass and geothermal resources may be represented as thermal units because their typical cost and operational profiles can be considered to be broadly similar to those of thermal units.

108. Solar and wind resources may be represented as transactions, which are contracts for the delivery of energy at a certain quantity, price, location, and period of time, because their capacity is available only at certain hours. Solar resources may be modeled with zero capacity during the night when the sun is hidden. Wind resources could have specific hourly throughput profiles based on wind forecasts.[47] The model and software conveniently allow the nomination of such transactions in particular hours.

109. Remote or off-grid technologies, such as commercial and residential PV and sea water air conditioning, may be represented as DSM or conservation programs, in view of their effect of reducing load approximately by the amount of energy available from them, and their inability, by their nature as off-grid resources, directly to serve load elsewhere on the grid.[48]

- In the model and software, an optimization is performed on both supply and demand resources. Supply resources are typically power generation facilities connected to the grid. Demand resources may be power generation facilities supplying particular customers, or DSM or energy saving programs that reduce load requirements.

- Estimates of cost and operational characteristics of off-grid resources serving specific customers may be developed. Off-grid resources may be treated as candidate projects, in much the same way that potential solar or wind grid-connected projects are included in the optimization as candidate renewable resources. Off-grid resources, therefore, are able to compete with alternative supply options in the determination of the optimal generation mix.[49]

D. Representation of Other Characteristics

[47] According to Datta, *Supra* Note 31 at 16-18, studies on the cost of integrating wind power across three time horizons, unit commitment of 12 to 24 hours ahead of dispatch, load following through the day, and regulation dealing with minute-by-minute variations, provide an "…an overwhelming result being that integration costs, at a range of wind penetration levels, are low."

[48] For a recommendation to evaluate distributed generation, see Warren S. Bollmeier II, *Preliminary Comments on the PUC Initial Concept Paper: Electric Utility Rate Design in Hawaii*, November 15, 2004, at 2. In the planned simulations, distributed generation resources may be considered and represented, if deemed necessary, as an off-grid resource achieving a load-reduction effect.

[49] For an expression of concern about the impact of combined heat and power ("CHP") systems on the baseline analysis, see Bonnet, *Supra* Note 18 at 6. In the planned simulations, CHP systems may be considered and represented, if deemed necessary, as a combination of a thermal unit selling to the grid and an off-grid resource achieving a load-reduction effect.

110. The payment of a capacity credit, which is a payment that may be provided in recognition of a plant's contribution to system reliability, for renewable resources may be considered.[50]

- A capacity credit, if deemed necessary, may be represented as a fixed payment offsetting a portion of the cost of renewable resources. The capacity credit level may be determined independently outside the planned simulations, and sensitivity analysis may be performed to determine if the capacity credit requires an upward or downward adjustment.[51]

- There seems to be much debate on the legitimacy of capacity credits for renewable resources. One view is that advances in technology may have allowed renewable resources to contribute to system reliability, and that renewable resources may therefore deserve a capacity credit.[52] Another view is that, with competition in generation and advances in financial analysis and techniques, the volumetric price paid to a renewable resource in a competitive market may be sufficient for cost recovery and capital contribution and may already reflect the benefit of including a renewable resource in the generation mix, and that a capacity credit may therefore be unnecessary.

111. The incorporation of financial instruments influencing the viability of renewable energy resources may be considered.[53] Various financial instruments, if deemed necessary, may be represented as fixed payments offsetting a portion of the cost of renewable energy resources.

E. Comments

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

- Modeling biomass energy resources;

- Modeling geothermal energy resources;

---

[50] For a discussion on the merits of capacity credits and how they can be calculated, see Datta, *Supra* Note 31 at 14-15. See also Lazar, *Supra* Note 13 at 8.

[51] According to a proposal, made in the context of a restructured power market, by Peter Cramton and Steven Stoft, "A capacity market that makes sense," January 15, 2005, at 1 available at http://www.cramton.umd.edu/papers2005-2009/cramton-stoft-a-capacity-market-that-makes-sense.pdf last visited on February 17, 2005, a "...locational capacity market pays suppliers based on their demonstrated ability to supply energy or reserves in shortage hours—hours in which there is a shortage of operating reserves..." and "...only supply that contributes to reliability is rewarded."

[52] *Supra* Note 50. For an expression of doubt that an energy-only market could ensure sufficient investment maintaining reasonable levels of reliability over time, and for an explanation of an approach that would ensure long-term generation adequacy but does not impede an efficient short-term energy market, see Miles Bidwell, "Reliability Options: A Market-oriented Approach to Long-term Adequacy," *Elec. J.*, Vol. 18 Issue 5, June 2005.

[53] According to Datta, *Supra* Note 31 at 18-20, "…comparatively little work has been done in Hawaii to determine the degree to which public-private financial partnerships could reduce the cost of renewables, without incurring direct costs to the state treasury," and the restoration of the Federal Production Tax Credit for renewable resource projects "…would make most wind projects in Hawaii more cost effective than combustion turbines or combined cycle units running on No. 2 fuel oil."

- Modeling hydro energy resources;
- Modeling solar energy resources;
- Modeling wind energy resources;
- Modeling off-grid renewable technologies;
- Modeling capacity credits; and
- Modeling various financial instruments.

Appendix A: Specific Assumptions for HECO

HECO	Input	Assumption	Source
Load	Energy sales	Growth rate between 0.61% and 3.35%	HECO
	Seasonal load shape	Constant	HECO
	Peak demand	Growth rate between 0.63% and 3.47%	HECO
Capacity and Generation	Minimum reserve margins	0%	HECO
	Maximum reserve margins	50%	HECO
Fuel and O&M Costs	Diesel	Growth rate between 0% and 6.11%	HECO
	Coal	Growth rate between 1.83% and 3.54%	HECO
	Biomass	0% growth	HECO
	Low-sulphur fuel oil	Growth rate between 0% and 9.28%	HECO
	Thermal unit costs	Thermal unit fixed and variable costs constant	HECO

Appendix B: Specific Assumptions for HELCO

HELCO	Input	Assumption	Source
Load	Energy Sales	Growth rate between 2.26% and 3.33%	HELCO
	Seasonal load shape	Constant	HELCO
	Peak demand	Growth rate between 3.02% and 3.35%	HELCO
Capacity and Generation	Mininmum reserve margins	20%	HELCO
	Maximum reserve margins	100%	HELCO
	Hydro energy generation	Constant	HELCO
	Hydro energy seasonal distribution	Constant	HELCO
Transactions	Transactions beyond 2005	Constant	HELCO
	Seasonal distribution of transactions	Constant	HELCO
Fuel and O&M Costs	INDS	Growth rate between 2.69% and 4.06%	HELCO
	Diesel	Growth rate between 0% and 5.89%	HELCO
	Coal	Growth rate between 0% and 3.65%	HELCO
	Prop.	Growth rate between 0% and 3.55%	HELCO
	Biomass	0% growth	HELCO
	Pump storage costs	Fixed and variable costs constant	HELCO
	Thermal unit costs	Fixed and variable costs constant	HELCO

Appendix C: Specific Assumptions for MECO (Maui, Molokai, and Lanai)

Maui

MECO (Maui)	Input	Assumption	Source
Load	Energy sales	Growth rate between 2.48% and 3.15%	MECO
	Seasonal load shape	Constant	MECO
	Peak demand	Growth rate between 2.16% and 2.96%	MECO
Capacity and Generation	Mininmum reserve margins	0%	MECO
	Maximum reserve margins	100%	MECO
Transactions	Transactions beyond 2005	Constant	MECO
	Seasonal distribution of transactions	Constant	MECO
Fuel and O&M Costs	Diesel	Growth rate between 0% and 5.97%	MECO
	Medium-sulphur fuel oil	Growth rate between 2.73% and 4.11%	MECO
	Biomass	0% growth	MECO
	Thermal unit costs	Fixed and variable costs constant	MECO

Molokai

MECO (Molokai)	Input	Assumption	Source
Load	Energy Sales	Growth between 0.71% and 2.32% in 2006-2020 and at the average of HECO, HELCO, Maui afterwards	EI/MECO IRP-2 Evaluation Report
	Seasonal load shape	Weighted average of HECO, HELCO, and Maui	EI
	Peak demand	Growth rate between 0.71% and 2.32% in 2006-2020 and at the average of HECO, HELCO, Maui afterwards	EI/MECO IRP-2 Evaluation Report
Capacity and Generation	Mininmum reserve margins	Average of HECO, HELCO, and Maui	EI
	Maximum reserve margins	Average of HECO, HELCO, and Maui	EI
Fuel Heat Content	Annual fuel heat content	Average of HECO, HELCO, and Maui	EI
	Fuel heat content	Average of HECO, HELCO, and Maui	EI
Fuel and O&M Costs	Diesel	Growth rate between 0% and 5.89% in 2006-2020 and at the average of HECO, HELCO, Maui DIES afterwards	EI/MECO IRP-2 Evaluation Report
	Thermal unit costs	Average of HECO, HELCO, and Maui	EI

Lanai

MECO (Lanai)	Input	Assumption	Source
Load	Energy sales	Growth rate between 0.96% and 2.03% in 2006-2020 and at the average of HECO, HELCO, Maui afterwards	EI/MECO IRP-2 Evaluation Report
	Seasonal load shape	Weighted average of HECO, HELCO, and Maui	EI
	Peak demand	Growth rate between 0.96% and 2.03% in 2006-2020 and at the average of HECO, HELCO, Maui afterwards	EI/MECO IRP-2 Evaluation Report
Capacity and Generation	Mininmum reserve margins	Average of HECO, HELCO, and Maui	EI
	Maximum reserve margins	Average of HECO, HELCO, and Maui	EI
Fuel Heat Content	Annual fuel heat content	Average of HECO, HELCO, and Maui	EI
	Fuel heat content	Average of HECO, HELCO, and Maui	EI
Fuel and O&M Costs	Diesel	Growth rate between 0% and 6.06% in 2006-2020 and at the average of HECO, HELCO, Maui DIES afterwards	EI/MECO IRP-2 Evaluation Report
	Thermal unit costs	Average of HECO, HELCO, and Maui	EI

Appendix D: Specific Assumptions for KIUC

KIUC	Input	Assumption	Source
Load	Energy sales growth	1% to 2.5%	EI
	Seasonal load shape	Constant	KIUC
	Peak demand	Proportional to 2004 sales	EI
Capacity and Generation	Wind plants spinning contribution	0%	EI
	Future non-renewable LM2500 plant minimum capacity	10% of maximum capacity	EI
	Future coal plant minimum capacity	Average (max capacity/min capacity) of similar plants at HECO	EI
	Maintenance and outage rates of alternative coal plants	Rates assumed for similarly sized coal plants at HECO Companies	EI
	Time until retirement for non-renewable alternatives	30 years	EI
	Minimum reserve margins	27%	EI/KIUC
	Maximum reserve margins	40% to 60%	EI
	Split of hydro energy generation between units	Proportional to units' generation capacity	EI
	Hydro energy seasonal distribution	Equal to 2004 seasonal distribution	EI
Fuel Heat Content and Burn Limits	Annual diesel and naptha heat content	Weighted average of monthly fuel heat content in KIUC data for 2004	EI/KIUC
	Coal heat content of future coal plants	Average of those for similarly sized future coal plants in HECO Companies	EI
	S1 Plant max and min burn limits	None	EI
Transactions	Transactions beyond 2005	Equal to 2003 levels	EI
	Seasonal distribution of transactions	Constant	EI
Fuel and O&M Costs	Annual fuel costs	Weighted average of monthly fuel costs	EI
	Future coal costs	Average of those for similarly sized future coal plants in HECO Companies	EI
	O&M for alternative renewable energy resources	Same as in-service year costs	EI
	Thermal unit costs	Constant	KIUC